STATE OF CONNECTICUT

SITING COUNCIL

Docket 370A: The Connecticut Light and Power Company application for a Certificate of Environmental Compatibility and Public Need for (1) The Greater Springfield Reliability Project consisting of a new 345-kV electric transmission line and associated facilities from the North Bloomfield Substation in Bloomfield to the Connecticut/Massachusetts border, together with associated improvements to the North Bloomfield Substation, and potentially including portions of a new 345-kV electric transmission line between Ludlow and Agawam, Massachusetts that would be located in the Towns of Suffield and Enfield, Connecticut; and (2) the Manchester Substation to Meekville Junction Circuit Separation Project in Manchester, Connecticut.	**DOCKET 370**
Docket 370B: NRG Energy, Inc. application pursuant to C.G.S. § 16-50*l*(a)(3) for consideration of a 530 MW combined cycle generating plant in Meriden, Connecticut	July 7, 2009

DIRECT TESTIMONY OF LOUISE MANGO

CONCERNING ENVIRONMENTAL EFFECTS
OF THE CONNECTICUT VALLEY ELECTRIC TRANSMISSION PROJECTS

The Connecticut Portion of the Greater Springfield Reliability Project
and
The Manchester Substation to Meekville Circuit Separation Project

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INTRODUCTION AND SUMMARY

Q. Would you please identify yourself and summarize your background regarding environmental matters associated with the Connecticut Light and Power Company's (CL&P's) Greater Springfield Reliability Project (GSRP) and Manchester to Meekville Junction Circuit Separation Project (MMP), collectively referred to as "the Projects"?

A. I am Louise Mango, an environmental consultant from Phenix Environmental, Inc. A copy of my resume is being filed separately. I have been involved in aspects of the Projects since approximately the fall 2006, when I first reviewed CL&P's general proposals for the New England East-West Solution (NEEWS). Since that time, I have worked on the team for the Projects, focusing primarily on alternative routing studies and environmental matters. Previously, I performed a similar function during the planning and permitting for the Middletown-to-Norwalk 345-kV Project and the Glenbrook Cables 115-kV Project.

Q. Are there any other personnel who may respond to cross examination regarding environmental matters for the Projects?

A. Yes. Mr. Donald Biondi, who is involved in CL&P's siting and permitting, will be available to respond to questions regarding the environmental aspects of the Projects. In addition, the compilation and analysis of environmental information for the Projects involved a number of specialized engineering and environmental consultants, any of whom may be asked to support this testimony by providing responses to inquiries about specific environmental or environmental resource-related topics.

For example, Burns & McDonnell, Inc. (BMcD), CL&P's project management and engineering consultant, worked on the construction engineering factors that affect environmental planning, alternatives design, and Project configurations. ENSR/AECOM, Inc. (AECOM) is the environmental consulting firm that compiled baseline environmental data for the Projects; conducted field investigations of water resources (wetlands and watercourses), amphibians, and biological resources (including threatened and endangered species surveys); and drafted portions of the Application to the Connecticut Siting Council (CSC or the Council) regarding environmental factors. Vanasse, Hangen Brustlin, Inc., a transportation / land development / environmental services consultant, performed specialized studies of the environmental resources at the North Bloomfield Substation. In addition, Raber Associates (Raber) performed cultural resource studies for both of the Projects.

Q. **What is the purpose of your testimony?**

A. The purpose of this testimony is to summarize the environmental and social/cultural factors that were considered during the analysis of routing and configuration alternatives and the development of plans for the Projects in order to avoid, minimize, or mitigate adverse effects on environmental and cultural resources. The testimony also describes how such environmental considerations will continue to be important as the design, certification, permitting, and construction of the Projects proceed, and during the operation and maintenance of the Project facilities. In addition, the testimony updates or clarifies environmental resource information presented in the Application.

The testimony addresses environmental matters regarding the proposed 12-mile Connecticut segment of the GSRP, which would extend from the North Bloomfield Substation in the Town of Bloomfield to the Massachusetts border (in the Town of Suffield), as well as the MMP.

In addition, the testimony reviews the environmental resources, potential environmental impacts, and route options considered for the 5.4-mile Connecticut segment of the "Southern Route Alternative" for the Massachusetts portion of the GSRP. Although CL&P does not prefer this alternative for the new 345-kV transmission line, if approved by the Massachusetts Energy Facilities Siting Board (ESFB), this transmission line segment in would be required and would be in addition to the 12-mile portion of the GSRP between the North Bloomfield Substation and the border.

Q. How is your testimony organized?

A. The testimony is organized by nine primary topics, as follows:

1. Approach used to compile baseline environmental data for the Projects, including field investigations.
2. Environmental criteria considered in identifying and evaluating alternative routes and transmission configurations (i.e., overhead and underground) for the transmission lines.

3. Review of environmental resources along the proposed route of the Connecticut portion of the GSRP, including the North Bloomfield Substation expansion.

4. Review of environmental resources along the MMP.

5. Discussion of potential environmental effects and mitigation measures for the GSRP and MMP.

6. Review of the environmental resources and potential effects of the underground cable system alternatives for the GSRP.

7. Review of the environmental resources and potential effects of the Connecticut portion of the "Southern Route Alternative" for the Massachusetts GSRP, including an underground transmission line variation.

8. The role of D&M Plans in environmental impact mitigation.

9. Conclusions.

1. <u>ENVIRONMENTAL DATA COLLECTION APPROACH</u>

Q. What approach was used to characterize existing environmental conditions for the Projects?

A. Environmental resource data for the Projects were compiled in accordance with the CSC's August 2007 *Application Guide for Terrestrial Electric Transmission Line Facilities*, and involved the compilation and analysis of Geographic Information System information, the collection / review of documents, the performance of field investigations, and consultations with representatives of state, federal, and local agencies. Primary published sources that were reviewed included the Connecticut Department of Environmental Protection (DEP) files (e.g., water quality information), soil surveys, U.S. Geological Survey maps, Federal Emergency Management Agency (FEMA) maps, and municipal land use plans.

Q. **Please briefly describe the environmental field studies performed for the Projects.**

A. In 2007 – 2008, field surveys were conducted of wetlands (including vernal pools), watercourses, amphibian breeding areas, and breeding bird habitats. Field reconnaissance of land uses and visual resources also was conducted. In January 2008, a baseline noise study was performed to characterize ambient sound conditions in the vicinity of the North Bloomfield Substation. Cultural resource studies were performed to compile information about the history of the Project areas; identify known archaeological, historic architectural, and historic engineering resources; and assess the potential archaeological sensitivity for discovering unrecorded sites along the proposed Project routes.

Q. **Are the results of these studies reflected in the Application?**

A. Yes. The environmental resources in the Project areas are described in Sections L and M of the Application (Volume 1) and are depicted on the maps in Volumes 2-4 and 9-11.

Q. **In identifying and evaluating environmental resources, did CL&P consult with the public or representatives of the municipalities in which the Projects would be located?**

A. Yes. CL&P solicited public and agency input during the CSC's formal Municipal Consultation Filing process, as well as during other public forums, including public meetings, open houses, and town inland wetland commission and planning and zoning commission meetings. Environmental resource issues identified through such venues have been and continue to be taken into consideration in the ongoing planning for the Projects, and in the environmental impact and mitigation analyses included in the Application (Section N, Volume 1).

2. ENVIRONMENTAL CRITERIA AND ALTERNATIVES ANALYSES

Q. What role did environmental factors play in the identification of the proposed and alternative routes for GSRP?

A. The avoidance, minimization, and mitigation of impacts to environmental and cultural resources were key considerations throughout the alternatives analysis processes for the Projects. As discussed in Section H of the Application (Volume 1), the selection of proposed routes for the GSRP involved an iterative process, during which alternative routing and transmission line design options were reviewed, taking into consideration first the overall Projects' objectives for providing new 345-kV transmission line links and then considering environmental, engineering, and cost factors. The routing objectives applicable to both Projects were:

- Comply with statutory requirements, regulations, and state and federal siting agency policies.
- Achieve a reliable, operable, constructible, and cost-effective solution.
- Maximize the reasonable, practical, and feasible use of existing linear corridors (e.g., transmission lines, highways, pipelines).
- Minimize the need to acquire property by eminent domain.
- Minimize adverse effects to sensitive environmental resources.
- Minimize adverse effects to significant cultural resources (archaeological and historical).

- Minimize adverse effects on designated scenic resources.

- Minimize conflicts with local, state, and federal land use plans and resource policies.

- Maintain public health and safety.

Q. Were these routing criteria applied to assess both overhead and underground alternative route options for the GSRP?

A. Yes, with some modifications due to the inherent differences between overhead and underground transmission line design, construction, and operation.

For example, as discussed in Section H of the Application, the configuration of overhead transmission lines allows flexibility, provided that a continuous right-of-way (ROW) of adequate width to accommodate a new line is available. Individual structures can often be designed and located to avoid or span conductors over sensitive environmental areas, such as wetlands, streams, or steep slopes. However, because overhead transmission lines require relatively wide ROWs to maintain safe clearances from electric wires, the availability of land that can be devoted to transmission line use – while avoiding effects on residential or commercial / industrial developments - is a critical routing criterion.

Certain of CL&P's existing transmission line ROWs in Connecticut are wide enough to accommodate additional overhead transmission lines. In contrast, due to factors such as limited land availability, cost, and effects on environmental resources and land uses, the acquisition and development of an entirely new "greenfield" transmission line ROW or the establishment of a new overhead transmission line adjacent to other existing linear corridors, such as highways or pipelines, is often difficult or impractical.

In comparison, underground transmission cable systems require a narrower ROW, but typically involve the excavation of a continuous trench (such that environmentally sensitive areas cannot be spanned) and the installation of underground splice vaults that must be accessible for maintenance purposes. Careful siting is required to avoid or minimize significant effects on environmental resources and other utilities, as well as to assure that the cables are immediately accessible should maintenance be required.

Q. Were any alternative sites considered for the proposed modifications to the North Bloomfield Substation?

A. No. Because the objective of the GSRP is to provide a new 345-kV interconnection at this substation (thereby completing a 345-kV "loop" in the Greater Springfield – northern Connecticut area), there are no viable options to the expansion of the existing substation. Furthermore, the existing substation occupies only approximately 7 acres of a 34-acre site owned by CL&P. The proposed modifications would be located entirely within this 34-acre site, and would require the additional development of only 2.7 acres, primarily located south of and abutting the existing developed portion of the property. Any alternatives, such as the development of an entirely new substation site on other property, would necessarily result in greater environmental impacts and costs associated not only with the development of the new substation, but also with the extension of the existing and proposed 345-kV lines to interconnect at such a new location.

For example, although CL&P does own property across Hoskins Road, to the west of the North Bloomfield Substation, this property is forested, such that extensive clearing would be required for the construction and operation of a new substation. In addition, the development of a substation in this location would require the extension of the existing 345-kV line (i.e., the 395 Line) that presently interconnects to the North Bloomfield Substation from the south, as well as the realignment of the proposed new 345-kV line to extend across Hoskins Road.

Q. **The proposed substation expansion is primarily to the south of the developed portion of CL&P's 34-acre site. Were alternative locations within CL&P's North Bloomfield Substation property considered for the expansion?**

A. The location for the substation expansion is constrained by: (a) the need to interconnect the existing 395 Line that extends into the substation from the south and the proposed (new) 345-kV line that would interconnect to the station from the north; and (b) the minimization of effects to environmental resources and land uses such as Griffin Brook, which abuts the existing substation on the east, and the homes and church located across Hoskins Road (to the west). In addition, CL&P has reduced the amount of additional land required for the substation modifications by reconfiguring existing facilities within the existing 115-kV switchyard on the already developed portion of the site. As a result, although the proposed expansion will require fill in wetlands, it represents the most practical, cost-effective, and least environmentally damaging on-site location for the expansion.

Q. Explain why alternative routes were not considered for the MMP.

A. The MMP is a circuit separation project and thus must be performed, at least in part, on CL&P's existing ROW where the two circuits to be separated are located. Although it would be possible to locate one or both of the separated circuits on a new ROW or in an underground configuration, such an option would be cost-ineffective; would result in comparatively significant effects on environmental resources; and would require the acquisition of easements from various private landowners.

Q. Please explain the characteristics of the MMP ROW that led to the determination that there are no feasible alternative routes or configurations for the circuit separation.

A. The 2.2-mile MMP ROW[1], all of which is located in the Town of Manchester, is typically 350 feet wide and traverses some of the few undeveloped parcels within this otherwise relatively densely populated area of the town. The existing ROW encompasses shrub land and forested areas, crosses the floodplains of the Hockanum River and Hop Brook, and traverses U.S. Route 6/44, Interstate 84, and the Tolland Turnpike. Nearby land uses consist of a mix of urbanized areas (e.g., residential developments, schools, Buckland Industrial Park), as well as

[1] The distance between Manchester Substation and Meekville Junction is approximately 2.5 miles. However, the circuit separation project only involves approximately 2.2 miles of this ROW.

recreational uses (hiking trails, boating) along and adjacent to the Hockanum River.

There are no off-ROW alternatives that would achieve the circuit separation objective (i.e., separation of the existing 115-kV and 345-kV lines that presently are located on the same transmission line structures) without requiring the creation of a new transmission line corridor. Given the land uses in the vicinity of the MMP route, such a new transmission line corridor would result in substantial adverse effects to environmental resources and/or substantially greater costs.

3. ENVIRONMENTAL FEATURES ALONG THE PROPOSED GSRP ROUTE, INCLUDING THE NORTH BLOOMFIELD SUBSTATION

Q. Please describe generally the proposed route of the Connecticut portion of the GSRP, and how this proposed route was selected for the Project, taking into consideration environmental factors.

A. The Connecticut portion of the 345-kV GSRP transmission line is proposed for location in an overhead configuration within CL&P's existing ROW that extends from the North Bloomfield Substation in the Town of Bloomfield to Granby Junction in the Town of East Granby (4.7 miles) and then from Granby Junction, continuing through the Town of East Granby and the Town Suffield to an interconnection with WMECO's proposed 345-kV transmission line at the Massachusetts border (7.2 miles). This ROW, which varies in width from 385 to 305 feet, has been dedicated to electric transmission use for more than 80 years and is presently occupied by 115-kV lines and, in some locations, a 23-kV distribution line.

The proposed overhead transmission line route was selected after first identifying and considering the use of other ROWs (e.g., highways) and other configurations (i.e., underground). The alternatives considered included the use of other linear corridors (e.g., highways, bicycle paths), and other configurations (e.g., underground cable system along the existing ROW and within road ROWs). CL&P's analyses determined that the proposed overhead line route along CL&P's existing ROW represented the most practical, cost-effective, and least environmentally damaging of the alternative alignments and configurations.

Q. **Are there any areas along the proposed transmission line route where additional ROW easements would have to be acquired for the development of the new overhead transmission line?**

A. Yes. Although most of the existing CL&P ROW is wide enough to accommodate the new 345-kV transmission line, an additional 3.2 acres of easements would have to be acquired from private landowners along two segments of the ROW in the Town of Suffield (i.e., between Phelps Road and Mountain Road, and east of Ratley Road). The property on which these easements would have to be acquired presently consists of upland forest.

Q. **Please describe the salient environmental features along the proposed GSRP route in Connecticut.**

A. The proposed 345-kV transmission line would be located predominantly within CL&P's existing ROW, which is characterized by both shrub-scrub cover types (consistent with utility use) and adjacent forested areas. Land uses in the vicinity of the ROW consist of agricultural land, forested areas, and scattered residential areas. The principal highways along the transmission line ROW are State Routes 189, 20, and 168.

The proposed 345-kV transmission line would span 25 watercourses (seven perennial and 16 intermittent). The largest watercourse along the route is the Farmington River. The GSRP route does not traverse any state-designated Stream Channel Encroachment Lines (SCELs).

Based on the results of the 2007 – 2008 field surveys, 60 wetlands were identified along the ROW (21 of these 60 wetlands also are associated with the watercourses along the route). Wetlands were delineated based on both state and federal jurisdictional criteria. For the most part, the federal and state wetland boundaries coincide (refer to Volumes 2, 9, and 11 of the Application).

Q. Why were federal jurisdictional wetlands delineated?

A. The boundaries of federal jurisdictional wetlands (the criteria for which are slightly less stringent than the criteria for Connecticut jurisdictional wetlands) were delineated as required for CL&P's application to the U.S. Army Corps of Engineers (USACE), New England District, for a joint permit pursuant to Section 10 of the Rivers and Harbor Act and Section 404 Clean Water Act. This permit application was submitted on June 19, 2009.

Q. How many of the identified wetlands also support amphibian habitat?

A. Amphibian studies, performed by AECOM during the 2008 spring amphibian breeding period, resulted in the identification of 18 wetlands – all along the ROW in the towns of East Granby and Suffield – that function as vernal pools and support amphibian breeding. Species observed in these areas included spotted salamanders, Jefferson salamander, marbled salamanders, wood frog, fingernail claims, and fairy shrimp.

Q. Is the proposed GSRP transmission line route in the vicinity of any federal- or state-designated threatened or endangered species?

A. Based on consultations with the U.S. Fish and Wildlife Service and the DEP Natural Diversity Data Base (NDDB), one federally- and state-designated endangered species (the dwarf wedge mussel) may occur in the Project area, along with six state-designated species of special concern (SSC). The dwarf wedge mussel reportedly occurs in the Farmington River, which the proposed transmission line will span. The six SSC species include the Eastern box turtle, Jefferson salamander, two mussel species (the Eastern pearlshell mussel, Eastern pond mussel), the Arrow clubtail dragonfly, and a plant (Bush's sedge). Like the dwarf wedge mussel, the Eastern pond mussel and dragonfly occur along the Farmington River, which the transmission line will span.

After consultations with DEP, CL&P conducted surveys for and confirmed the presence of the Jefferson salamander and a small population of Bush's sedge within the ROW. CL&P is continuing to consult with the DEP regarding options for mitigating adverse effects on these species as a result of the construction and operation of the Project. Potential mitigation measures under consideration may include seasonal construction timing windows to avoid critical periods in the species' lifecycles, pre-construction monitoring, the use of barrier fencing, and construction contractor training in species identification and avoidance.

Q. **Will the GSRP line route traverse designated state and local parks, wildlife management areas (WMAs), and hiking / bicycling trails?**

A. The GSRP line route follows CL&P's existing ROW across one state-designated WMA – the Newgate WMA –north of Turkey Hills Road in the Town of East Granby. In this area, the WMA abuts CL&P fee-owned property, which CL&P leases to the DEP for wildlife management purposes, north and south of Turkey Hills Road.

In the Town of Suffield, the route traverses land owned by the Suffield Sportsman's Association and managed for uses such as archery, shooting, fishing, and hunter safety training. The proposed 345-kV line route also traverses generally parallel to the Metacomet Monadnock Mattabesett Trail, which extends through portions of Connecticut, Massachusetts, and New Hampshire and was designated as the New England National Scenic Trail in March 2009. The proposed transmission line route is aligned along CL&P's existing ROW across the trail in East Granby (at the Hatchett Hill Road crossing) and in Suffield (north of Phelps Road).

The proposed route traverses near, but does not cross, the Farmington Valley Greenway (a former railroad corridor that has been converted to a biking and hiking trail) and the Fox Run at Copper Hill Golf Course in the Town of East Granby. Similarly, the proposed route is located near, but does not traverse, the Suffield Land Conservancy's Spencer Woods Preserve and Alcorn Wildlife Preserve in the Town of Suffield. The route extends north of the Town of Bloomfield's Farmington River Park, which encompasses 78 acres along the Farmington River, approximately 0.5 miles south of the transmission line ROW.

Q. Is the GSRP located within the state-designated coastal boundary?

A. No.

Q. What cultural resources were identified near the proposed route?

A. CL&P commissioned a specialized cultural resources consulting firm (Raber) to identify known cultural resources in the vicinity of the GSRP route in Connecticut, as well as to evaluate the potential sensitivity of the route for locating as yet undiscovered archaeological sites. Based on Raber's evaluations, no cultural resources listed on the National or State Registers of Historic Places (NRHP, SRHP) are located within 0.25 mile of the proposed GSRP transmission line route. However, three historic cemeteries are located within 0.25 mile of the route and approximately 6.7 miles of the 12-mile ROW is considered sensitive for the location of undocumented Native American archaeological sites. CL&P has consulted with the State Historic Preservation Office (SHPO) regarding the GSRP and expects to continue to work with the SHPO regarding the performance of site-specific field studies of cultural resources as more detailed Project designs are developed.

Q. What are the environmental characteristics of the North Bloomfield Substation site?

A. CL&P's 34-acre site, which is generally bounded by Hoskins and Tarriffville roads on the west and north, respectively, includes approximately 7 acres that are developed for the existing substation and approximately 27 acres of undeveloped land. The undeveloped portions of the property are characterized by forested upland and wetland areas, as well as open fields. Griffin Brook flows to the north through the site, directly east of the developed substation. The brook is characterized by a wooded riparian zone. The site is screened from adjacent areas by both deciduous and coniferous vegetation.

CL&P owns property across Hoskins Road, to the west of the site. St. Andrews Church and cemetery are situated to the northwest, while residences are located along Hoskins Road to the southwest of the site. No state- or federally-designated threatened, endangered, or SSC species are reported to occur on the site.

No designated recreational resources are located in the immediate vicinity of the substation. However, the Town of Bloomfield's Marion K. Wilcox Park, which consists of approximately 212 acres and includes hiking trails and picnic areas, is located about 0.14 mile southwest of the substation, west of Hoskins Road.

Q. Were any special field environmental investigations conducted of the substation site?

A. Yes. Wetlands / watercourse studies, biological resource surveys, and cultural resource investigations were conducted, as well as an ambient noise survey. The results of the water resource, biological, and cultural resource studies were included in the analyses for the GSRP as a whole. The noise study, which was performed by BMcD personnel in January 2008, determined that ambient sound levels ranged from 36.4 dBA during the night time to 49.6 dBA during the early evening; these levels are characteristic of suburban / rural environments.

Q. Where does CL&P propose to expand the North Bloomfield Substation?

A. Within the 34-acre site, CL&P proposes to expand the developed portion of the station by approximately 2.7 acres, mostly to the southeast and southwest. A portion of the expansion will be located within wetlands and within the Griffin Brook floodplain.

4. ENVIRONMENTAL FEATURES ALONG THE MMP ROUTE

Q. Please describe the environmental characteristics and land uses in the area of the MMP route.

A. The 2.2-mile MMP ROW traverses upland and wetland forested and shrub land areas along and in the vicinity of the floodplains of the Hockanum River and Hop Brook, as well as various commercial uses and several local, state, and interstate highways (i.e., Olcott Street, Thrall Road, U.S. Route 6/44 Interstate 84, and the

Tolland Turnpike). The crossing of Interstate 84 is just east of that highway's intersection with Interstate 291.

Land uses surrounding the ROW consist predominantly of urban and suburban developments. The Town of Manchester landfill, which accepts bulky and solid waste from around the state, is located to the west of the MMP route, north of the Manchester Substation. The town's wastewater treatment plant also is located in this area.

Q. The MMP will require the acquisition of ROW on one parcel near the Tolland Turnpike. What environmental resources characterize this parcel?

A. The environmental sections of the Application (Sections L and N) inadvertently omitted a discussion of this parcel, which consists of an approximately 2,400 square foot (approximately 0.055 acre) area located within a commercial development on the north side of the Tolland Turnpike. All of the lands surrounding this parcel are presently encompassed within CL&P's existing ROW (refer to Mapsheet 2 of 3 in Volume 9 of the Application). This small parcel (where the additional ROW will have to be acquired for the MMP) consists of a paved parking lot, which is bordered by commercial uses in an upland setting. The acquisition of this inholding as part of the MMP ROW will have no adverse effects on the environment.

Q. What water resources are located along the MMP route?

A. The existing ROW crosses five perennial watercourses (including the Hockanum River and Hop Brook), as well as two intermittent streams. The route traverses the SCEL associated with the river. As illustrated on the Volume 9 maps, several existing CL&P transmission line structures are presently located within this SCEL. The MMP route also traverses 13 wetlands, as delineated based on 2008 field surveys performed by AECOM. Two of these wetlands provide amphibian breeding habitat.

Q. Are there any threatened or endangered species located along the MMP?

A. Consultations with the DEP NDDB identified one species of bird (the Barn Owl) as potentially occurring in the MMP vicinity. CL&P conducted field surveys for this species in 2008. No owls were observed during these surveys and only one small area of potential Barn Owl foraging habitat (which consists of open, grassy fields, old fields, or wet meadows) was located on the ROW. In addition, in correspondence dated September 28, 2008, the DEP recommended that no large-diameter trees (which can provide nesting cavities for Barn Owls) be cut along the Hockanum River.

Q. Does the MMP traverse any parks, WMAs, or other recreational areas?

A. The MMP does not traverse any WMAs or state-designated recreational areas. However, it does cross or is located near several local and regional recreational areas.

Within CL&P's existing ROW, the MMP traverses near the James M. Leber Memorial Field, a town-owned park that includes one baseball field and associated facilities. The Verplanck Elementary School and playground is located approximately 400 feet east of the MMP (near Manchester Substation), whereas the Howell Cheney Vocational Technical School and East Catholic High School (and associated playing fields) are located approximately 250 and 600 feet east of the edge of the ROW, respectively.

Wickham Park, a non—profit foundation, owns a 250-acre property located approximately 0.2 mile to the west of the ROW, north of Interstate 84 and southwest of Interstate 291. The Wickham Park property contains gardens, open fields, ponds, picnic areas, a bird sanctuary, hiking trails, and sports facilities and is used for a wide variety of events (e.g., weddings, disc golfing, dog championships).

In addition, the MMP ROW crosses several recreational trails along Hop Brook and the Hockanum River. The Hockanum River, which is considered a linear park, and its associated floodplain are used for a variety of recreational purposes, including fishing, canoeing, kayaking, and hiking / cross-country skiing. The Hockanum River Linear Park Committee (HRLPC) maintains hiking trails along and in the vicinity of the river. The ROW traverses the HRLPC's Laurel Marsh, New State Road, and Verplanck trails. These trails, which are used year-round, also are listed as officially dedicated greenways by the Connecticut Greenways Council.

The Verplanck and Laurel Marsh trails are located along Hop Brook and the river, respectively, south of U.S. Route 6/44, whereas the New State Road Trail is located along the river south of Interstate 84. The Verplanck Trail is used periodically for educational purposes by the Verplanck Elementary School.

Q. Please summarize the results of cultural resource studies of the MMP.

A. The review of recorded prehistoric and historic site information reveals that there are eight documented Native American archaeological sites and two poorly-documented EuroAmerican sites within approximately 1 mile of the MMP ROW. Overall, approximately 0.3 mile (in discontinuous sections) of the 2.2-mile MMP ROW was determined to be potentially sensitive for the location of unrecorded Native American sites. No EuroAmerican archaeological sites listed on or eligible for listing on the NRHP or SRHP are reported or likely to occur along the MMP.

One potentially significant standing historic structure (the Charles Bunce House, which is eligible for listing on the NRHP) was identified within approximately 0.25 mile of the MMP. However, this house is located southwest of the Manchester Substation, south of Center Street, Hartford Road, and a modern commercial building.

5. POTENTIAL ENVIRONMENTAL EFFECTS AND MITIGATION MEASURES

Q. What potential environmental effects were evaluated with respect to the construction and operation of the Projects?

A. The construction and operation of the GSRP and MMP will result in similar types of environmental effects. The Projects' potential short- or long-term effects on the following resources were evaluated:

- Topography, geology, and soils
- Water resources and water quality (wetlands [including vernal pools], watercourses, floodplains, groundwater, and pubic water supply areas)
- Biological resources
  - Riparian and upland vegetation
  - Wildlife
  - Amphibians
  - Fisheries
  - Threatened/endangered species.
- Land uses (including scenic and recreational resources; open space and protected areas; local, state, and federal land use plans; existing and future development)
- Road, railroad, and utility crossings
- Cultural resources
- Air quality and
- Noise

Q. **What potential effects would the Projects have on topography, geology, and soil resources?**

A. The Projects will have negligible and localized effects on topography and geology. Topography will not be affected except in locations where grading is required to provide stable and safe areas for construction access or other construction work. Blasting is not expected to be required to install the transmission line structures. However, if necessary, any blasting would be performed in accordance with state and local requirements.

Soil resources will be affected by the creation or expansion of access roads along the existing ROWs, as well as by vegetation clearing and the earth-disturbing activities required to install transmission line structures. The development and use of temporary staging areas, material storage sites, conductor pulling sites, and contractor yards also could temporarily cause soil disturbance.

However, all activities involving soil disturbance would be performed in accordance with the CL&P and state requirements (including CL&P's *2007 Connecticut Best Management Practices Manual* and the *2002 Connecticut Guidelines for Soil Erosion and Sediment Control,* as well as the DEP's *General Permit for the Discharge of Stormwater and Dewatering Wastewaters from Construction Activities*). CL&P would prepare Project-specific *Stormwater Pollution Control Plans* that would incorporate these requirements, including specifications for the deployment and maintenance of temporary erosion and sedimentation control measures during construction.

Temporary erosion and sedimentation controls (e.g., silt fence, hay or straw bales, water bars, or equivalent) will be installed, maintained, and routinely inspected during construction. After the completion of structure and conductor installation along segments of the ROWs, CL&P will implement permanent erosion controls, as appropriate to site-specific conditions. Such measures may include not only re-seeding and mulching, but also the use of biodegradable or other erosion control netting, installation of permanent diversion berms, etc. The objective will be to stabilize the disturbed portions of the ROW through revegetation and, if necessary, structural practices.

Q. The expansion of the North Bloomfield Substation will require work in wetlands and near Griffin Brook, as well as near several residences along Hoskins Road. Will any special erosion and sediment control measures be applied to avoid or minimize the potential for surface water runoff or sedimentation from the expansion site?

A. As CL&P described during consultations with the Town of Bloomfield (August 2008) regarding the substation expansion, the substation expansion work will conform to all applicable erosion and sedimentation control plans and permit requirements. Excess soil generated as a result of grading will be removed from the property, rather than stockpiled on site near the water resources. In addition, construction will be sequenced to the extent possible to minimize the time that bare earth is exposed (and therefore subject to erosion) prior to temporary or permanent stabilization. Upon the completion of the expansion construction, the 2.7-acre area will be stabilized with trap rock or other ground cover.

Q. What potential effects would the Projects have on water resources (wetlands, watercourses, and lakes)?

A. For the most part, the construction of the Projects will result in localized and temporary effects to surface water resources associated with the development of new access roads, or the improvement of existing access roads, across wetlands and smaller watercourses within the transmission line ROWs. The Projects also could cause short-term adverse effects on water quality associated with the installation, use, and removal of these equipment / construction vehicle access roads, as well as from potential erosion and sedimentation from upland portions of the ROW into water resources.

The proposed overhead transmission lines will span water courses. However, some tall-growing riparian vegetation will have to be removed to allow the safe operation of the line. Such vegetation would be removed selectively.

During construction, CL&P would require its construction contractors to adhere to specific procedures designed to avoid or minimize adverse effects to water resources, and to conform to the conditions of the CSC approvals for the Projects and the DEP and USACE permits. The mitigation measures that CL&P has identified thus far to minimize adverse effects on water resources are listed in Section N.1.2 of the Application.

The operation of the Projects would not affect water resources, with the exception of locations where transmission line structures or permanent access roads must be unavoidably located in floodplains or wetlands. In such areas, the fill associated with these facilities would represent a long-term effect. CL&P will coordinate with the involved regulatory agencies (e.g., DEP, USACE) to define mitigation for such effects.

Q. What specific effects would the development of the proposed transmission lines have on wetlands?

A. The proposed GSRP and MMP transmission line routes will follow existing ROWs, within which wetlands have historically been affected by periodic vegetation maintenance, by the placement of structures within certain wetlands, or by the creation and use of access roads. The development of the proposed transmission lines along these existing ROWs will result in similar types of effects.

Specifically, beneath the existing transmission lines, CL&P's vegetation maintenance program prevents the growth of large-diameter woody (tree) species, thereby sustaining scrub-shrub or emergent marsh type wetlands. Along the GSRP ROW, 11 existing transmission line structures are presently located in wetlands. Along the MMP ROW, nine existing structures are within wetlands. The development of the Projects will result in incremental effects on wetlands associated with additional vegetation clearing and ROW maintenance; the improvement or creation of access roads; the unavoidable installation of new transmission line structures in wetlands and/or the placement of temporary crane pads in wetlands; and the installation of temporary structures in wetlands (to allow the safe pulling of conductors across roads).

CL&P estimates that the GSRP 345-kV transmission line would result in less than 0.1 acre of permanent fill in wetlands. Approximately 2.1 acres would be temporarily affected by construction work areas, such as crane pads or temporary access roads, and approximately 26 acres of forested wetlands would be converted to scrub-shrub or emergent wetlands.

As a result of the development of the MMP, approximately 1.4 acres of forested wetlands would be converted to scrub-shrub or emergent wetlands. Less than

0.05 acre of wetlands would be permanently affected as a result of structure foundations or access roads, whereas approximately 3.8 acres of wetlands would be affected by temporary construction work areas.

Overall, the principal effect to wetlands along the Project ROWs will be the conversion of forested wetlands to scrub-shrub or emergent type wetlands for the life of the Projects. Although long-term, this change in vegetative cover type will represent a modification to, but not a net loss of, wetlands.

For the GSRP and the MMP, the unavoidable installation of new structures within wetlands will represent a permanent loss of wetlands. Similarly, some access roads will have to remain permanently in wetlands to allow safe ingress / egress to structures along the ROW (refer to Tables N-1 and N-2 in the Application for a summary of potential wetland effects as a result of the GSRP and MMP, respectively). To compensate for wetland losses, CL&P will work with the USACE and DEP to develop mitigation programs.

Q. What efforts has CL&P made to avoid, minimize or mitigate long-term adverse effects on water resources?

A. As discussed in Section N.1.2 of the Application, in the planning and design of the proposed Projects, CL&P has attempted to avoid, minimize, and/or mitigate adverse effects to wetlands and watercourses, while still following existing utility ROWs. CL&P has designed the Projects to locate transmission line structures and permanent access roads outside of wetlands wherever possible, and also proposes to span watercourses, preserving as much riparian vegetation as safely possible.

Q. How will the expansion of the North Bloomfield Substation affect wetlands and watercourses?

A. The 2.7-acre expansion of the substation will unavoidably affect approximately 0.78 acre of wetlands, including 0.76 acre of mixed forested / scrub-shrub wetland and 0.02 acre of forested wetlands. Most of these wetlands are within an area that was previously affected by the 978 expansion of the substation to its present configuration. The proposed substation expansion also will permanently displace approximately 400 cubic yards of flood storage capacity within the 100-year floodplain of Griffin Brook.

To mitigate these effects, CL&P will create compensatory flood storage along other portions of Griffin Brook and will work with the DEP and USACE to define and implement compensation options for the permanent loss of wetland functions and values within the substation expansion area. Such compensation is expected to be part of the overall wetland mitigation plan that CL&P expects to develop for the GSRP as a whole, working with the USACE and DEP.

Q. How will the MMP affect the SCEL along the Hockanum River?

A. CL&P recognizes that, given the location of the existing ROW along the river, new structures will unavoidably have to be located within the SCEL. CL&P has conducted further analyses of the effects of such development within the SCEL on the floodplain environment, and has provided such information as part of its June 19, 2009 application to the DEP for a SCEL permit. Any work within the SCEL will conform to the requirements of the DEP SCEL permit conditions.

Q. How much forested vegetation will have to be cleared for the GSRP (including the North Bloomfield Substation) and the MMP?

A. An estimated 132 acres of forested vegetation (upland and wetland) would have to be cleared for the GSRP. This includes approximately 103 acres of upland forest and 26 acres of palustrine (mostly deciduous) wetland forest along the GSRP ROW, as well as approximately 2.7 acres of forested areas (about 2 acres of upland and 0.78 acres of wetland) at the North Bloomfield Substation.

For the MMP, CL&P estimates that approximately 5.1 acres of forest land would be affected, including about 3.7 acres of uplands and 1.4 acres of wetlands.

Q. How will the conversion of these forested areas affect vegetation and wildlife resources?

A. Because the Projects would be along existing ROWs, the effects on vegetation and wildlife resources would be limited and in some respects would be positive. Although certain vegetation would have to be removed to safely accommodate the construction and operation of the transmission facilities, the vegetation types found along the routes are common in the region and vegetation removal would represent a negligible overall impact on wildlife habitats and populations.

Further, the creation of additional shrubland habitat (and the preservation of such existing habitat) along the maintained ROWs would represent a long-term positive effect because shrubland habitat (like any other early successional habitats) is otherwise declining in New England as a result of various factors (e.g., development, ecological succession, absence of fire). In Connecticut, transmission line ROWs are considered a major source of shrubland habitat.

Q. What effect would the Project have on the vernal pools (18 along GSRP and two along MMP) and the rare species identified along or in the vicinity of the existing ROWs?

A. CL&P has designed structure locations and construction work areas to avoid amphibian breeding areas and the habitats of designated rare species, wherever possible. In addition, CL&P has identified various measures to mitigate the effects of the Projects on amphibian breeding periods / habitats and on state species of concern (refer to Section N.1.3.5 – N.1.3.7 and N.1.9.5 of the Application), and has been coordinating with the DEP regarding such mitigation procedures.

Most recently, on March 26, 2009, CL&P met with the DEP to review the Projects and the proposed mitigation measures. These measures are described for the GSRP in the "*GSRP Connecticut Component Rare Species Mitigation Summary*" included as Exhibit LM-1. The DEP's April 3, 2009 letter response endorsing these procedures also is provided in Exhibit LM-1.

Q. Will the proposed Projects be consistent with land-use plans and policies?

A. Yes. With the exception of the 3 acres of additional easement that will have to be acquired in the Town of Suffield along the GSRP ROW and the 0.055-acre parcel adjacent to the Tolland Turnpike along the MMP ROW, the proposed Projects would be installed within existing, long-established electric transmission ROWs or on CL&P-owned property.

For the GSRP, the 3 acres of new easement required represents only 2% of the approximately 145 acres that would be affected by the development of the new 345-kV transmission line as a whole. The 145 acres includes the 3 acres of ROW expansion and the lands within CL&P's existing ROW that would be required for the construction of the new 345-kV transmission line (includes assumed 100-foot-wide additional forested vegetation clearing, access road development, crane pads, new structure foundations, etc.). An additional 2.7 acres will be affected by the expansion at the North Bloomfield Substation.

The 2.2-mile MMP would affect a total of 8.9 acres, and would require an additional easement amounting to 0.055 acre near the Tolland Turnpike.

Q. **How would CL&P minimize effects on recreational areas along the ROWs as a result of the Projects' construction and operation?**

A. As discussed in the Application, CL&P will consult with the representatives of the affected recreational areas to identify site-specific mitigation measures, including possible scheduling of construction work to avoid key recreational use periods and ROW restoration measures appropriate to the recreational uses.

Q. **What effects would the Projects have on visual resources?**

A. Given public concerns regarding the visibility of overhead transmission structures, CL&P's base line design for the GSRP has attempted to minimize the height of the proposed structures to the extent possible and to generally match the height of the proposed 345-kV line structures to the height of the existing transmission lines that presently occupy the ROWs. However, in some areas, taller structures may be selected by the Council for the purpose of increasing the height of the line conductors to reduce magnetic field levels at the edges of the ROWs. In general, the impact of the new structures on visual resources would be incremental because the proposed Projects would be aligned along existing ROWs (where the overhead transmission lines have been part of the landscape for decades) and because – for the most part – the new structures are expected to be in the same general locations as the existing structures.

The long-term effect on visual resources in any particular area also would depend on various factors, such as:

- The appearance (type and height) of the transmission structures that presently occupy the ROWs.
- The appearance (type and height) of the transmission structures proposed for the ROWs.
- The extent to which vegetation presently screens the ROW and existing structures from view.
- The amount of vegetation clearing that would be required to accommodate the new transmission line facilities.
- The extent to which topographic conditions limit views of the ROWs.
- The land uses adjacent to and near the ROWs.
- Individual public perceptions concerning views of the transmission line ROWs and structures.

In order to provide the Council and interested stakeholders with a basis for estimating the visual effects of the proposed construction, CL&P included in the Application "cross sections" of each different overhead transmission line configuration, showing the existing and future structures to scale, as well as the locations of the existing and proposed structures within the ROWs. Each cross section also depicts the total ROW width, width of the existing vegetatively maintained portion of the ROW, and the additional vegetation width proposed for clearing to accommodate the new transmission lines. The Application also included photographic simulations at representative locations, showing the anticipated appearance of the ROWs after Project construction.

Q. Please describe how the visual appearance of the existing ROWs between the North Bloomfield Substation and the Massachusetts border will change if the GSRP is constructed as proposed.

A. The development of the GSRP would modify the visual appearance of CL&P's existing ROWs as a result of:

(1) The removal of vegetation to allow the construction of the new 345-kV transmission line, followed by the long-term maintenance of a wider portion of the ROW in non-forested vegetation to allow the safe operation of the new line; and

(2) The addition of the new 345-kV line structures and conductors, which in some locations would be taller and more visible than the existing 115-kV line structures.

Q. Have you evaluated the computer animated simulations that CL&P commissioned to further evaluate the visual effects of the proposed 345-kV line from various locations?

A. Yes. I have reviewed the simulations prepared by Truescape of the post-construction ROW as it would appear from Newgate Road in East Granby and Phelps Road in Suffield, and as it would appear in a panoramic view from a point on the Metacomet Trail on Suffield Mountain (also in Suffield).

Q. What is your opinion regarding the visual effects of the Project?

A. Changes to the landscape are largely a matter of individual perceptions and value judgments. Generally, however, due to the location of the existing ROW, and the screening afforded by topography and vegetation, the development of the new 345-kV transmission line will not be apparent as a dominant landscape element. The new 345-kV transmission line would alter views from certain specific locations, particularly where the ROW crosses public roads. Vegetation clearing required for the new 345-kV line will make portions of the existing and new transmission line structures more visible in some locations. During the growing season, when trees are leafed out, the structures will generally be less visible than in the winter months. In addition, at certain vantage points, the taller delta monopole structures, if used, will be more visible from a panoramic landscape perspective.

Q. Please describe the change that would occur in the appearance of the 2.2 miles of ROW between Manchester Substation and Meekville Junction as a result of the MMP circuit separation.

A. The existing 350-foot-wide ROW is presently occupied by multiple transmission lines. The circuit separation project will involve the construction of a new steel-monopole 115-kV single-circuit line, configured with a 345-kV design and hardware, between these existing structures. The existing lattice-steel structures are generally 130 to 155 feet in height, and the new monopole structures would typically be 155 feet in height. As a result, the overall visual effect of the MMP will be incremental and highly localized.

Q. What effect will the construction and operation of the Projects have on transportation and traffic patterns?

A. The construction of the Projects would result in limited and localized effects on transportation patterns associated with the movement of construction equipment and vehicles to and from the ROWs. The operation of the Projects would have no effect on transportation or traffic.

For the most part, the public road network in the Project areas affords ready access to the ROWs for construction vehicles and equipment. During the construction period, construction workers traveling to and from work sites, as well as the movement of construction equipment, would cause temporary and localized increases in traffic volumes on local roads near the transmission line routes. CL&P would employ police personnel to direct traffic at construction work sites along roads (e.g., where the ROWs cross public roads), as needed, and would erect appropriate traffic signs to indicate the presence of construction work zones.

In general, equipment and vehicular movements along the ROWs would be via on-ROW access roads. These existing access roads are depicted in the maps in Volumes 9 and 11.

The proposed transmission line conductors (wires) would span various roads. None of these overhead spans would affect traffic patterns, except possibly during the limited times where the conductors are installed.

Q. **How would CL&P minimize or avoid adverse effects on cultural resources?**

A. CL&P expects to perform further field investigations for cultural resources when the final Project configurations are defined. Such field investigations will be performed in accordance with a SHPO-approved work plan, and the results of such surveys will be provided for the SHPO's review and approval. CL&P is committed to conformance to federal and state regulatory requirements for protecting significant cultural resources sites.

Q. **Please summarize how potential noise effects would be minimized during the construction and operation of the Projects.**

A. The construction of the Projects will result in short-term and highly localized increases in sound levels associated primarily with the operation of construction equipment, truck movements, earth moving activities, structure foundation preparation, structure installation, and work associated with the North Bloomfield Substation expansion. Such construction-generated noise will be localized to the vicinity of construction work sites and will occur during the daytime, when human sensitivity to noise is lower.

The expansion of the North Bloomfield Substation will involve the addition of a second 345-kV/115-kV autotransformer, as well as circuit breakers and a control enclosure. Computer models of the anticipated noise from the new transformer (the only source of additional noise) determined that the predicted noise levels will not exceed the day- or night-time Connecticut noise limits.

6. <u>THE GSRP UNDERGROUND VARIATIONS</u>

Q. Please summarize the underground transmission cable alternative routes that CL&P identified and evaluated for the GSRP.

A. As part of the alternatives evaluation process, CL&P identified four potential routes for an underground 345-kV cable system, involving the use of cross-linked polyethylene (XLPE) cables, splice vaults, and transition stations (refer to Sections H.4, H.5, and J.2 for a details regarding the locations of the four underground variations and a discussion of underground cable-system construction steps). The four underground alternatives, each of which would represent an alternative to a portion of the proposed overhead transmission line, included two routes along existing road ROWs (i.e., the Newgate Road and the State Route 168/187 underground variations) and two underground routes along portions of CL&P's ROW. All of the underground variations are depicted on the maps in Volumes 9 and 11.

Q. Please summarize the potential environmental issues associated with the development of an underground cable system along CL&P's existing transmission line ROW.

A. Either of the two underground variations along the existing CL&P ROW would create significant disturbance to soil resources (due to the need for continuous trenching and excavations for the splice vaults); would increase the potential for erosion and sedimentation off the ROW; and would involve direct impacts to water resources during construction as a result of trenching across watercourses and wetlands. Permanent access along the entire length of the underground variations also would be required for the operation and maintenance of the cable system. For the two variations along the CL&P ROW, this would permanently convert 8.7 and 11.2 acres to access road use (refer to Table H-4). In addition, for the same two variations along the CL&P ROW, the use of flowable fill, rather than native backfill in the trench and splice vaults could have long-term effects on water resources.

Because the potential effects to water resources could be largely avoided by configuring the 345-kV transmission overhead (as is proposed), neither of the underground variations would represent the least environmentally damaging practical alternative for the Project. Further, in correspondence dated April 3, 2009 (refer to Exhibit LM-1), the DEP expressed serious concerns that any underground alternative would involve land-altering activities that would be very disruptive to state-listed species of concern in the GSRP area.

Q. Could adverse environmental effects be minimized if the 345-kV transmission line were located underground, along either of the in-road ROW?

A. The alignment of the 345-kV line underground, within road ROWs would minimize, but would not avoid all, adverse environmental effects. For the two underground cable-system variations that are aligned along public roadways, even if the cable system could be installed entirely within the paved road travel lanes, vegetation adjacent to and/or overhanging the roads would be affected. For example, trees that overhang the roads would have to be trimmed or removed in order to allow the safe operation of the construction equipment. Tree roots could be affected by trenching and splice vault installation, ultimately resulting in impacts to forested vegetation. In addition, areas adjacent to the paved roadways may need to be used for construction staging, spoil storage, or the development of temporary equipment detours (if access is not otherwise possible via alternative road routes). Finally, the cable system would have to traverse (e.g., be trenched through or installed beneath) the water resources that the roads typically bridge.

Q. Wouldn't it be possible to install an underground cable system using subsurface technology (such as horizontal directional drilling (HDD) or a type of jacking / boring), which would avoid direct impacts to environmental resources?

A. HDD and jack / bore techniques were used on recent CL&P projects. However, both of these techniques are extremely costly, time consuming, and require deep excavations, which – if groundwater is encountered – must be continuously dewatered. Large temporary construction staging areas are typically required on each side of the resource to be drilled or bored. In addition, HDD can involve inadvertent returns of drilling mud to the surface of the ground or river bottom being traversed. Although the drilling mud typically does not contain hazardous substances, the clean-up requirements that apply to it are the same as those for such substances. As a result, these methods are not without environmental challenges.

Q. What effect would the construction and operation of the underground cable-system variations along public roadways have on transportation and traffic patterns?

A. In-road construction would be extremely time-consuming and would require the concurrence of the Connecticut Department of Transportation (CTDOT) and local highway authorities to schedule work so as to minimize adverse impacts associated with traffic detours, disruption, and congestion. Measures also would have to be taken to maintain access to nearby land uses during the construction period, as well as to avoid affecting other buried infrastructure.

Q. Please describe the potential effects of the underground construction on cultural resources.

A. If cable-system construction is performed within public road ROWs and similar previously disturbed areas, the potential for adverse impacts to cultural resources typically would be limited. However, further cultural resource studies would have to be performed to assess the potential effects of the route variations. In addition, the Newgate Road Underground Variation would be located directly in front of the NRHP-listed Old Newgate Prison, as well as another NRHP-listed historic structure and an old cemetery. CL&P's cultural resource consultant has stated that the excavations required for the cable system in this area would potentially affect the integrity of these significant historic resources.

Q. Please summarize and compare the environmental effects of each of the underground cable-system segments, compared to the segments of the proposed overhead 345-kV line that each would replace.

A. Compared to the proposed overhead configuration, the underground cable-system segments would result in significantly greater soil disturbance, increasing the potential for erosion and sedimentation. Each underground variation also would require considerable time to construct.

The in-ROW underground variations would directly impact various wetlands and watercourses as a result of the trenching that would be required for the cable-system duct banks and for splice vaults.

The in (or along) road ROW underground variations would extend through residential areas where the relatively long construction period would have localized effects on traffic patterns and nuisance effects (duct, noise) on local residents. Water resources also could be affected by the underground crossing techniques.

7. <u>THE CONNECTICUT PORTION OF THE "SOUTHERN ROUTE ALTERNATIVE"</u>

Q. Describe the proposed route of the 5.4-mile Connecticut portion of the "Southern Route Alternative" to the Massachusetts segment of the GSRP.

A. This alternative, which would continue into Massachusetts to the South Agawam Junction on the west and Hampden Junction on the east, would extend approximately 1.1 miles through the Town of Suffield and 4.3 miles through the Town of Enfield. Along this alternative route, the new 345-kV line would span the Connecticut River (at the Massachusetts / Connecticut border), Interstate 91, and U.S. Route 5. It would be aligned within an existing CL&P ROW that is presently occupied by 115-kV facilities.

The route would cross not only the Connecticut River, but also four other streams (including Four Mile Brook and Waterworks Brook) and 27 wetlands (including three vernal pools that support amphibian breeding). In addition, approximately 3.7 miles of the Enfield portion of the ROW traverses a Connecticut Aquifer Protection District.

The ROW would traverse forested areas on either side of the Connecticut River, as well as agricultural lands and various suburban residential areas. (Note that a short segment of the alternative traverses into Massachusetts at the Connecticut River, such that on the eastern side of the river, the route is aligned through a wooded floodplain area in Massachusetts before re-entering Connecticut in the Town of Enfield.) Four state-listed threatened, endangered, or special concern species were identified by the DEP NDDB as occurring in or near the Connecticut River. These include the Bald Eagle, shortnose sturgeon, two species of clubtail dragonfly.

Q. Why was an underground cable-system variation identified for a portion of the Southern Route Alternative?

A. Approximately 3.7 miles of the Southern Route Alternative ROW in Enfield, beginning west of Interstate 91 and extending east to Mayfield Road (refer to the maps in Volumes 9 and 11), is bordered on both sides by densely developed residential uses, including subdivisions, condominiums, and apartment complexes. Pursuant to Connecticut law, CL&P identified an underground cable-system variation as an option to the proposed overhead alignment near these residential developments.

Q. Please describe the Massachusetts State Route 202 / Enfield Underground Line Route Variation.

A. This 4.3-mile underground variation, which would be located entirely in Enfield, would replace a 3.7-mile segment of the overhead line route. The underground transmission system would consist of 345-kV XLPE cables and associated splice vaults.

The variation would be aligned primarily within or adjacent to two-lane state and local road ROWs (e.g., Brainard Road), except for a 0.4-mile segment that would be aligned within CL&P's existing transmission line ROW. The variation would traverse several small water resources, none of which were identified as vernal pools. Similarly, no state-listed species of concern are located along the variation.

Q. Please describe how the visual appearance of the 5.4-mile Connecticut sections of the "Southern Route Alternative" would change if this alternative was chosen and overhead line construction was approved.

A. The existing ROW along the Southern Route Alternative is occupied by 115-kV line on wood-pole H-frame structures that typically are 60 feet in height. In Suffield and along portions of the route in western Enfield, assuming CL&P's base line design (refer to the cross-sections in Volume 10 of the Application), steel- or wood-pole H-frames, typically 90 feet in height, would be added to the ROW. Approximately 105 feet of additional vegetation would have to be cleared and maintained along the ROW to accommodate the new 345-kV transmission line. Where the ROW traverses densely developed residential areas in Enfield, the new 345-kV line structures would have to be taller delta-type structures, typically 110 to 130 feet in height, as detailed in CL&P's supplemental Field Management Design Plan.

Substantial changes to the appearance of the ROW would occur as a result of the addition of the 345-kV line along the Southern Route Alternative. The construction and operation of the line would require the removal of substantial mature forested vegetation that presently occupies the un-unused portions of the ROW and provides a visual buffer than limits existing views of the transmission structures. The taller height of the structures, particularly in Enfield, also would make the new 345-kV line particularly visible.

Q. **What would be the environmental effects of the construction and operation of the Southern Route Alternative, either in the all-overhead configuration or the hybrid overhead / underground configuration (i.e., with the incorporation of the underground variation)?**

A. The environmental effects associated with the construction and operation of this alternative – involving either configuration option – would be similar to those described for the proposed Connecticut portion of the GSRP and the underground variations to the GSRP. However, if the EFSB selects the Southern Route Alternative for the Massachusetts portion of the GSRP, then the Connecticut portion of the Alternative would be required, along with the 12-mile proposed Connecticut portion of the GSRP between North Bloomfield and the Massachusetts border. This would result in at least 5.4 more miles of new 345-kV transmission line in Connecticut (6.1 miles if the hybrid overhead / underground route is selected), and would involve greater additional environmental impacts due to the construction and the operation / maintenance of the facilities.

8. ROLE OF THE DEVELOPMENT AND MANAGEMENT PLAN IN MITIGATING ENVIRONMENTAL EFFECTS

Q. How will the impact mitigation measures identified in Section N of the Application be incorporated into the construction plans for the Projects?

A. After Council certification of the Project, CL&P will prepare Development and Management (D&M) Plans for the Projects that will reflect detailed engineering design and that will incorporate the environmental measures proposed in the application, as well as any certificate and permit conditions included in approvals from the CSC, the DEP, and the USACE. The D&M Plans will conform to the CSC's requirements. The D&M Plans will be submitted to the CSC for review and approval, prior to the commencement of construction.

Q. What information will be included in the D&M Plans?

A. While the exact contents of the Project-specific D&M Plans will be based on the CSC's Order, the D&M Plan can be expected to include information concerning the Project facilities and land requirements; procedures for access road development and water resource crossings; general construction procedures; construction scheduling; work site and public safety during construction; traffic control at road crossings; requirements for erosion and sediment controls; requirements for excavation dewatering; and procedures for excess spoil disposition, among other topics. CL&P will conduct further field investigations of the certificated routes in order to refine construction plans. The DEP and USACE permits also may be appended to the D&M Plans and will be part of construction contracts for the Projects.

Q. How will compliance with the D&M Plans be monitored?

A. CL&P's subconsultants will monitor the contractors' compliance with the procedures specified in the D&M Plan(s). CL&P also would be willing to hire, if directed by the Council, an independent environmental inspector to conduct periodic (typically weekly) inspections of environmental aspects of the construction, as detailed in the D&M Plans.

9. CONCLUSIONS

Q. Based on your analyses, what are your conclusions regarding the potential environmental effects of the GSRP and MMP as proposed by CL&P?

A. Both Projects maximize the use of existing ROWs that are presently and have historically been dedicated to utility use. The proposed overhead transmission lines can be designed, constructed, and operated to avoid or minimize adverse effects on environmental resources. Further, any unavoidable adverse effects, such as permanent filling in wetlands as a result of structure foundations, can be effectively mitigated. CL&P has committed to perform such mitigation as may be required and to adhere to the environmental requirements that will be included as part of the Council's approval and that will be incorporated as conditions of the USACE and the DEP permits.

STATE OF CONNECTICUT
DEPARTMENT OF ENVIRONMENTAL PROTECTION
FRANKLIN WILDLIFE MANAGEMENT AREA
391 ROUTE 32
NORTH FRANKLIN, CT 06254
TELEPHONE: (860) 642-7239

April 3, 2009

Mr. Donald D. Biondi
Transmission Siting and Permitting
Northeast Utilities
107 Selden Street
Berlin, CT 06037

re: Greater Springfield Reliability Project

Dear Mr. Biondi

What a pleasure to meet you on March 26, 2009 regarding the Greater Springfield Reliability Project. The materials provided to me before the meeting were: the application to the Connecticut Siting Council Volume 11 of 11 dated October 2008, Section E, Section L; Description of Existing Environment along proposed line routes at the North Bloomfield substation, Section M; Existing Environment: Underground line route...and Section N.; Potential Environmental Effects and Mitigation Measures. At the meeting, I was handed a technical memo re: Greater Springfield Reliability Project CT Component Rare Species Mitigation Summary.

While we did not discuss mitigation measures for a possible underground alternative to this project, I want to reiterate that any underground alternative would be a serious concern to the Connecticut Department of Environmental Protection's Wildlife Division. The land altering work would be very disruptive to most listed wildlife species. Additionally, any underground trenching in the riverbed of the Farmington River where the federally listed freshwater mussel species, dwarf-wedge mussel, is located would trigger at consultation with the U. S. Fish and Wildilfe Service per the Endnagered Species Act. In that case, you should forward a detailed project proposal to the U. S. Fish and Wildlife Service (USFWS) for their information and notification (Susi vonOettingen, U. S. Fish and Wildlife Service, 70 Commercial Street, Suite 300, Concord, NH 03301-5087, (603) 223-2541). The Wildlife Division will be happy to assist the USFWS and you in the consultation process.

Regarding the Memo:

1. The DEP Wildlife Division concurs with the seven measures to protect Jefferson salamanders that were presented (pages 2-3). Tree clearing should be done in September and October to minimize impacts and wood chip ramps located every 30'.

2. The DEP Wildlife Divison concurs with the six measures to protect Eastern Box Turtles that were present (pages 3-4).

3. The DEP Wildife Divison concurs that the two measures to protect Eastern Pearlshell Mussel that were presented (page 4).

4. The DEP Wildlife Divison concurs with the two measures to protect the Arrow Clubtail Dragonfly, Dwarf wedgemussel and the Easten Pond Mussel in the Farmington River (page 4).

5. The DEP Wildlife Divison concurs with the measure to protect Bush's sedge on the ROW (page 4).

6. The DEP Wildlife Divison concurs with the measure to protect Barn owls (page 6).

7. The DEP Wildlife Divison concurs with the four measures to protect Wood Turtles (page 6). Additionally, since wood turtles hibernate in riparian corridors, if the work is done between November and April (the dormant period for wood turtle) no on-site monitor will be needed.

8. The DEP Wildlife Divison concurs with the two measures to protect Eastern Hognose snake (page 7).

If you have any additional questions, please feel free to contact me at Julie.Victoria@ct.gov. Thank you for the opportunity to comment.

Sincerely,

Julie Victoria
Wildlife Biologist
Franklin Swamp Wildlife Management Area
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Connecticut Light & Power

The Northeast Utilities System

AECOM

Technical Memorandum

To:	The Connecticut Department of Environmental Protection	**Date:**	March 26, 2009
From:	Northeast Utilities Service Company d/b/a The Connecticut Light and Power Company	**File:**	
RE:	Greater Springfield Reliability Project CT Component Rare Species Mitigation Summary	**CC:**	Don Biondi (NU) Jerry Fan (BMCD) Chris Fritz (BMCD) Tim O'Sullivan (AECOM) Jamie Durand (AECOM) Rob Young (Haley & Aldrich)

The Connecticut Light & Power Company (CL&P) initiated communication with the Connecticut Natural Diversity Database (NDDB) and the Department of Environmental Protection (CT DEP) regarding the Greater Springfield Reliabilty Project (GSRP) and associated rare species in October 2007. As a result of ongoing communication, on right-of-way (ROW) environmental surveys, and one consultation meeting that occurred on April 1 2008, CL&P identified ten species of concern on or adjacent to the GSRP ROW. The attached table entitled, *GSRP: Rare Species Summary*, lists the identified species. The following is a summary of surveys completed to date and a discussion of the mitigation measures CL&P plans to employ for each of the species.

Jefferson Salamander (*Ambystoma jeffersonianum*)

NDDB informed CL&P of the potential presence of Jefferson salamanders on or in close proximity to the GSRP ROW south of Hatchett Hill Road in East Granby, CT. During the April 1, 2008 meeting with the CT DEP and the GSRP team, the CT DEP recommended that CL&P representatives perform live trapping (using minnow traps) in an effort to locate breeding adults, as well as conduct surveys designed to locate Jefferson salamander egg masses. These surveys were recommended in all areas mapped as potential Jefferson salamander habitat.

The live trapping and egg mass surveys were performed on the ROW in East Granby, CT during Spring 2008. The surveys were performed in accordance with a protocol submitted by ENSR/AECOM to the CT DEP, and under a Scientific Collector's (Wildlife) Permit issued by the CT DEP. The mapping used for the field surveys included the data obtained from the NDDB.

Potential amphibian breeding habitats in three wetlands (W9-222, W9-223 and W9-224) were surveyed on the subject reach of the ROW for evidence of Jefferson salamander utilization. The wetland locations are depicted on Figure 1 (attached). The field surveys confirmed the presence of adult Jefferson salamanders in wetlands W9-223 and W9-224. Jefferson salamanders were not confirmed in wetland W9-222. After completion of the surveys, ENSR/AECOM generated a Special Animal Survey Form and supporting materials, including mapping and submitted this data to the CT DEP, as well as a report which documented the findings of the surveys.

Prior to confirming the Jefferson salamander breeding habitats within wetlands W9-223 and W9-224, the proposed alignment for the GSRP placed one structure and associated temporary crane pad in vernal pool habitat within wetland W9-224 as depicted in Figure 2 (attached). Following confirmation of the Jefferson salamander habitat, the Project team evaluated options to reduce direct impacts to the breeding habitats of the Jefferson salamanders to the extent practicable. The GSRP team developed an alternate Project design, as shown in Figure 3 (attached). Preliminary impacts associated with each design are presented in tabular format in the lower right corner of each figure, as well as in Table One below.

Each design will result in some tree clearing of forested uplands and forested wetlands, the latter including vernal pool habitat. In the Alternative Design, the removal of Structure 22 (near existing structure 3153), and its associated crane pad from the identified vernal pool habitat, requires that an additional area of upland forest be cleared. Given the extent of upland habitat in this area, this option would be preferred over the original design. The Alternative Design is preferred because it has lesser amounts of wetland/vernal pool habitat impacts, and there are extensive areas of upland habitat throughout the area in question.

Table One. Design options for the GSRP ROW in the area of Hatchett Hill Road, East Granby, CT.

	Vernal Pool Impacts			Wetland Impacts			Upland Impacts	
	Structure Impacts (sq. ft.)	Pad Impacts (sq. ft)	Clearing Impacts (sq. ft.)	Structure Impacts (sq. ft.)	Pad Impacts (sq. ft.)	Clearing Impacts (sq. ft.)	Upland Clearing (sq. ft.)	Access Roads (sq. ft.)
Impact Type	Perm	Temp	Perm	Perm	Temp	Perm	Perm	
Original Design	39	5,233	23,492	157[1]	16,663[1]	114,259	74,943	35,666
Alternative Design	0	0	23,492	78[2]	7,138[2]	114,741	91,636	32,103

[1] Pole structures 22 (existing structure 3153) and 23 (existing structure 3154)
[2] Pole structure 23 (existing structure 3154) only

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate effects on the Jefferson salamander population in the subject area of the ROW:

- As indicated in the CSC application and subject to pending negotiations with the CT DEP, CL&P is prepared to adhere to the seasonal restriction (October through February) for the vegetation removal portion of the Project, as it is likely to have the highest impact to the confirmed vernal pool habitat on the ROW. However, the Jefferson salamander habitat overlaps with Eastern box turtle (*Terrapene carolina*) habitat, and the CT DEP is currently recommending that clearing activities be conducted during the active period (late spring, summer and early fall) for the box turtle. Therefore, some compromise will be needed regarding the scheduling of tree clearing in this area.
- Siting the proposed structure locations outside of confirmed amphibian breeding pools.
- Using temporary timber mats on new access roads instead of constructing gravel access roads in the vicinity of amphibian breeding habitat.

- Minimizing the removal of low-growth vegetation surrounding the breeding pools during the initial ROW clearing activities.
- Incorporating the protection and maintenance of low-growth vegetation within and around the amphibian breeding pools into CL&P's vegetation maintenance program for the ROW.
- Implementing an effective erosion and sediment control plan to avoid and/or minimize the deposition of sediment into the breeding pools.
- In addition, due to the extended time period through which sediment and erosion controls will need to be in place, CL&P will make the necessary accomodations to facilitate unencumbered amphibian access to and from the identified vernal pool habitat by providing wood chip ramps on either side of the sediment and erosion controls and/or providing openings in the erosion control barriers. ENSR/AECOM has installed wood chip ramps with success at other sites with similar issues. CL&P will work with the NDDB to arrive at a mutually acceptable frequency of wood chip ramps along the sediment and erosion controls.

Eastern Box Turtle (*Terrapene carolina*)

The March 10, 2008 Connecticut Department of Environmental Protection (CT DEP) response letter indicated the potential presence of Eastern box turtles (*Terrapene carolina*) on or in close proximity to the GSRP right-of-way (ROW) in four locations. Three of these locations intersect the GSRP ROW for a total of approximately 2.25 miles, encompassing approximately 25 proposed structure locations. In addition, during the course of the environmental assessment of the ROW which partly consisted of wetland delineation activities and associated data collection, Eastern box turtles were observed on the ROW in two locations. Both observations were made within areas not previously mapped as habitat for the Eastern box turtle. Special animal survey forms and supporting documentation were generated and submitted to the CT DEP for each of these observations. Therefore, based on the information from the CT DEP and field observations, there are five areas along the subject ROW that potentially function as Eastern box turtle habitat. These areas are depicted in Figures 1 through 5.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate effects on the Eastern box turtle population(s) in the subject areas of the ROW:

- During the Eastern box turtle active period, a CT DEP approved turtle ecologist/monitor will be present whenever construction activities take place in mapped Eastern box turtle habitats. Said turtle monitor shall sweep all active work space daily. Any Eastern box turtles encountered shall be removed from active work space to ensure their safety.
- A contractor awareness program will be developed and implemented to ensure all contractors working in mapped Eastern box turtle habitats can identify the turtles and are made aware of the proper handling and care procedures for the species should one be observed in active work space.
- To the extent that it is possible, within mapped Eastern box turtle habitats, and when not in use, all construction vehicles and equipment shall be parked on roadways and not in Eastern box turtle habitat.
- Installing turtle exclusion fencing around the work area prior to construction.
- Minimizing removal of low-growth vegetation in all Eastern box turtle mapped habitats during the initial ROW clearing activities.
- Implementing an effective erosion and sediment control plan to avoid and/or minimize the deposition of sediment into wetland habitats.

Eastern Pearlshell Mussel (*Margaritifera margaritifera*)

The March 10, 2008 CT DEP response letter indicated the potential presence of Eastern pearlshell mussel in close proximity to the GSRP right-of-way (ROW). The identified habitats occur to the east of Granby Junction in Muddy Brook and do not intersect with the ROW. However, identified wetlands and watercourses that occur on the ROW are tributary to Muddy Brook in this area.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate potential effects to this rare mussel:

- Minimizing removal of low-growth vegetation in all wetland areas which are tributary to Muddy Brook during the initial ROW clearing activities.
- Implementing an effective erosion and sediment control plan to avoid and/or minimize the deposition of sediment into wetland habitats.

Arrow Clubtail Dragonfly (*Stylurus spiniceps*), Dwarf Wedgemussel (*Alasmidonta heterodon*), Eastern Pond Mussel (*Ligumia nasuta*)

The March 10, 2008 CT DEP response letter indicated that the arrow clubtail dragonfly, dwarf wedgemussel and Eastern pond mussel all occur in the Farmington River near the Spoonville Bridge. To accommodate the proposed new transmission lines, some tree clearing will be required on the north and south sides of the river, as well as on an island in the river itself. No mechanized clearing equipment will be utilized during the clearing process. It is anticipated that all trees on the subject island will be cut by crews which gained access to the island on foot and no heavy equipment will be utilized. Subsequent to tree felling, the trees will be winched across the river channel and up the slope to Tunixs Avenue. In addition, the river will not be crossed by construction equipment which will be utilized during the construction of new structures and the installation of the new lines.

To ensure that no rare mussels are negatively impacted during the tree removal process CL&P is proposing a rare mussel survey in this area. If any rare mussels are located they would be relocated to other suitable habitat. Said work would be conducted under a valid Scientific Collection Permit issued by the CT DEP and would be performed in accordance with a CT DEP approved protocol.

The substrate of the river in the area that could be potentially impacted during the tree removal process consists of bedrock, rock, cobble and gravel with lesser amounts of sand. Therefore, it is not anticipated that the area would be utilized by the clubtail dragonfly. Accordingly, CL&P does not propose surveys for this species.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate potential negative effects to the Farmington River:

- Minimizing removal of low-growth vegetation in areas adjacent to the river during the initial ROW clearing activities.
- Implementing an effective erosion and sediment control plan to avoid and/or minimize the deposition of sediment into riverine habitats.

Bush's Sedge (*Carex bushii*)

The March 17 2008, CT DEP response letter indicated the potential presence of Bush's sedge on the ROW in East Granby, CT. In response to this information ENSR/AECOM initiated a botanical survey designed to locate this rare plant in the identified area. As a result of the survey, a small population of Bush's Sedge was discovered along the western edge of the service road approximately 200 feet north of existing utility tower no. 3144. The population appeared to consist of two plants with four fruiting culms (stems) present. The population was threatened by young black birches, bittersweet vines, and shade from a nearby field juniper. Encroaching vegetation was pruned by hand to release the sedge culms.

An intensive search of the area where a population of Bush's Sedge was previously reported (as indicated in the March 17, 2008 response letter from the CT DEP) resulted in no additional observations of Bush's Sedge. It is possible that changes in the vegetative cover due to the regeneration of the woody shrubs and vines may have contributed to the loss of the previously reported population of Bush's Sedge in the ROW. The area currently supporting the observed Bush's sedge plants is located well to the north of the existing NDDB record.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate potential negative effects to the observed population of Bush's sedge:

- The location of Bush's sedge will be fenced off with highly visible snow fence and avoided during construction.

Barn Owl (*Tyto alba*)

The April 24, 2008 CT DEP response letter indicated there are historic records of the Barn Owl in the vicinity of the Manchester to Meekville Junction Line Separation Project component of the GSRP. The letter also stated that if work was to occur in any Barn Owl habitats a survey should be implemented during the March through April nesting period. In response to that request, ENSR/AECOM initiated a Barn Owl survey on the subject ROW. Field work consisted of three ground surveys conducted on April 16 and 27, and May 8, 2008. The purpose of the surveys was to identify any on ROW habitats which could potentially be utilized by Barn Owls for nesting and/or hunting.

As a result of the surveys, one area not dominated by shrub and sapling thickets or mature trees was identified as potential foraging habitat for barn Owls. This area contains a large wet meadow in the floodplain of the Hockanum River and is dominated by reed canary grass (*Phalaris arundinacea*). This area could potentially be utilized by Barn Owls as hunting habitat. Although Barn Owls were not observed, large diameter trees with suitable cavities within nearby woods may provide nest sites. A full breeding bird survey was also implemented for the Manchester to Meekville Junction ROW as part of the requirements imposed by the Connecticut Siting Council (CSC). The full Barn Owl survey report was attached as an addendum to the Inventory of Breeding Bird Species and Habitats Report, which was submitted as part of the CSC application.

Site Specific Mitigation

Limited tree clearing will be necessary as part of the proposed Project. In order to ensure no impacts to potential breeding habitat provided by any large cavities which may be present in any trees on the ROW, CL&P will implement a nesting tree cavity survey prior to removing any trees on the ROW.

Additional Field Observations

As stated above, CL&P is aware of ten rare species on or adjacent to the GSRP ROWs. Eight of these were communicated to the Project by the CT DEP. The remaining two species were observed by ENSR/AECOM biologists during the course of environmental surveys on the subject ROW.

Wood Turtle (*Clemmys insculpta*)

One wood turtle was observed adjacent to Griffin Brook at the North Bloomfield Substation site in Bloomfield, CT. The observation was documented by generating and submitting to the CT DEP a Special Animal Survey Form. This form was accompanied by a cover letter, photograph and mapping of where the animal was observed.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate effects on the wood turtle and associated habitats at the above referenced area:

- During the wood turtle active period, a CT DEP approved turtle ecologist/monitor will be present whenever construction activities take place adjacent to the North Bloomfield Substation. To ensure their safety any wood turtles encountered shall be removed from active work space and placed in the direction they were moving when first observed.
- A contractor awareness program will be developed and implemented to ensure all contractors working at the North Bloomfield Substation can identify the turtles and are made aware of the proper handling and care procedures for the species should one be observed in active work space.
- Minimizing removal of low-growth vegetation in all areas adjacent to Griffin Brook during the initial ROW clearing activities.
- Implementing an effective erosion and sediment control plan to avoid and/or minimize the deposition of sediment into wetland habitats. These measures would also provide some measure of protection as they would preclude wood turtles from accessing additional active work space.

Eastern Hognose Snake (Heterodon platirhinos)

During the course of the Bush's sedge survey, one Eastern hognose snake was observed on the ROW in East Granby, CT. Like the wood turtle mentioned above, the hognose snake observation was documented by generating and submitting to the CT DEP a Special Animal Survey Form. This form was likewise accompanied by a cover letter, photograph and mapping of where the animal was observed.

Site Specific Mitigation

CL&P is committed to implementing the following measures to mitigate any negative effects to the Eastern hognose snake:

- During the Eastern hognose snake active period, a CT DEP approved snake ecologist/monitor will be present on the ROW between Tunxis Avenue and Hatchett Hill Road whenever construction activities take place. Any hognose snakes encountered shall be removed from active work space to ensure their safety.
- A contractor awareness program will be developed and implemented to ensure all contractors can identify the snakes and are made aware of the proper handling and care procedures for the species should one be observed in active work space.

General Discussion Items

The CT DEP has provided contradictory preferences regarding construction activities and the Eastern box turtle. The March 10, 2008 response letter indicates a preference for work to be done in the dormant season of the turtles, which has been identified as October through April. However, as a result of the April 1, 2008 meeting with the GSRP team, the CT DEP indicated a preference for tree clearing to occur during the active period to avoid disturbing any hibernating turtles. The Project assumes that it is the CT DEP's preference that tree clearing activities take place during the box turtle active period, if timing restrictions are agreed upon. The Project is requesting confirmation of this.

In the area south of Hatchett Hill Road in East Granby, where Jefferson salamander habitat overlaps with Eastern box turtle habitat, clarification from the CT DEP regarding the preferred time of year to implement tree clearing is required. The CT DEP has recommended tree clearing be carried out in the dormant period of the Jefferson salamander (October through February), while at the same time recommending tree clearing be done during the active period (late spring, summer and early fall) for the Eastern box turtle. Some compromise will be needed for the area where the two species are known to coexist.

As stated in the CSC application, the CL&P has committed to the installation of turtle exclusion fencing around the "work area". CL&P requests clarification from the CT DEP regarding the definition of "work area." If turtle exclusion fencing is implemented, CL&P would prefer its use be limited to areas immediately associated with the construction of proposed new structures, and recommends against the implementation of said fencing along the length of mapped Eastern box turtle habitats. Large areas of silt fencing will result in the restriction of movement through the landscape by reptiles, amphibians and small mammals. The Massachusetts Natural Heritage and Endangered Species Program currently recommends against this practice of installing exclusion fencing along linear projects for the reasons stated above.

Thank you for your consideration of the information presented in this memorandum.

STATE OF CONNECTICUT

SITING COUNCIL

The Connecticut Light and Power Company application for a Certificate of Environmental Compatibility and Public Need for (1) The Greater Springfield Reliability Project consisting of a new 345-kV electric transmission line and associated facilities from the North Bloomfield Substation in Bloomfield to the Connecticut/Massachusetts border, together with associated improvements to the North Bloomfield Substation, and potentially including portions of a new 345-kV electric transmission line between Ludlow and Agawam, Massachusetts that would be located in the Towns of Suffield and Enfield, Connecticut; and (2) the Manchester Substation to Meekville Junction Circuit Separation Project in Manchester, Connecticut.	DOCKET NO. 370
APPLICATION OF NRG ENERGY, INC. PURSUANT TO CONNECTICUT GENERAL STATUTES § 16-50*l*(a)(3)	DOCKET NO. 370B July 7, 2009

DIRECT TESTIMONY OF MARIA FUSCO SCHELLER ON BEHALF OF CL&P CONCERNING NON-TRANSMISSION SYSTEM ALTERNATIVES

Q. Ms. Scheller, please introduce yourself and your colleague to the Siting Council.

A. I am Maria Fusco Scheller. With me to assist me in my responses to questions from the Council, parties, and intervenors is my colleague Kenneth Collison. We are employed by ICF International, a multinational consulting firm founded in

1969 and headquartered in Fairfax, Virginia. Each of us has provided curriculum *vitae* setting forth our professional qualifications and experience relevant to our work on the Greater Springfield Reliability Project (GSRP), which are attached as exhibits A and B to this testimony.

Q. Does the consulting practice of ICF International include work in the energy sector?

A. Yes, the division that Mr. Collison and I work in, known as ICF Resources, LLC (ICF) specializes in energy and natural resource issues. Our clients include energy utilities, governments, major corporations and multilateral organizations in North America, Asia, Europe, and Latin America. These clients include the United States Department of Energy, the Federal Energy Regulatory Commission, and the United States Environmental Protection Agency, as well as major power producers and state, regional, and local governmental organizations and agencies.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and summarize a report prepared by ICF under my supervision. The report (the "Report") is titled "Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Greater Springfield Reliability Project", dated September 2008 and included in Volume V of the siting application. I understand that a copy of this report with portions of Chapter 5 and Exhibits A-2 and A-3 redacted to comply with Critical Energy Infrastructure Information (CEII) requirements was included in Volume 5 of the

Application, and a complete copy of Chapter 5 and the redacted exhibits were included in the "CEII Appendix" to that Application.

Q. Please summarize ICF's experience related to the assessment of potential non-transmission alternatives to electric transmission projects.

A. We have extensive experience in performing transmission assessments and other evaluations that require modeling of the transmission system of the continental United States and Canada, taking into account the economics of the power plants and the physical and electrical characteristics of the transmission grid. We have performed many studies requiring modeling of the New England power system. In addition, we perform integrated resource planning studies, and that work is supported by our extensive experience in advising clients concerning central power plant, combined heat and power, distributed generation, energy efficiency and demand-side management projects.

Q. Please tell the Council how ICF came to perform a non transmission alternatives assessment for the Greater Springfield Reliability Project (GSRP).

A. In December 2007, ICF was retained by Northeast Utilities Service Company (NUSCO) and National Grid U.S.A. to perform non-transmission system alternatives analyses for the each of four New England East West Solution (NEEWS) projects, starting with the Rhode Island Reliability Project, and then moving on the Greater Springfield Reliability Project, the Interstate Reliability Project, and finally the Central Connecticut Reliability Project.

Q. What is the status of that work?

A. We concluded our evaluation of potential alternatives to the Rhode Island Reliability Project and delivered our report of that work in August, 2008. That report has since been presented to the Rhode Island Energy Facilities Siting Board, in support of National Grid's pending application for approval of the Rhode Island Reliability Project. We concluded an assessment of non-transmission alternatives to GSRP in September, 2008; after our report of that evaluation was presented to the Connecticut Energy Advisory Board (CEAB), we executed a supplemental power-flow study at the direction of the CEAB. Our work on the Interstate Reliability Project is underway, but still in its preliminary stages. We have not started work on the Central Connecticut Reliability Project evaluation, except to the extent that much of the modeling work that is required for the initial projects is relevant to the latter this.

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Q. Are the Report and the data and conclusions set forth in it correct, to the best of your knowledge and belief?

A. Yes.

Q. Do you have any corrections to make to the Report?

A. No.

Q. Did ICF assist CL&P in responding to data requests directed to it concerning ICF's work?

A. Yes, we did.

Q. I have provided you with copies of CL&P's previously filed responses to Data Requests Q-OCC-011, Q-OCC-012, and Q-O-013. Are these responses true and correct to the best of your knowledge and belief?

A. Yes.

Q. Are there any corrections required to any of these responses, insofar as they concern the ICF Report?

A. No.

Q. Please summarize the work ICF did with respect to identifying potential non-transmission alternatives to GSRP.

A. First, we worked with NUSCO planners to build a model that was equivalent to the 2012 power-flow planning case used by the ISO-NE working group in developing the needs analysis for GSRP and the NEEWS projects. We could not simply load a model obtained from NUSCO into our system because we use a different power-flow analysis program than that used by NUSCO and ISO-NE. This primarily involved saving the NUSCO case in an alternate file format which could be read by the software ICF relies on[1]. Once we were satisfied that we had

[1] ICF utilizes GE's PSLF model while ISO-NE relies on Siemens PSS®E software. Both software packages simulate the power system load flow.

created a model that agreed in all important respects with that used to generate the power flows that determined the need for GSRP, we then updated several assumptions to reflect more recent information available since the creation of that power-flow case. The resulting power-flow case reflected our starting or base case power-flow for the 2013 year. Next, we developed our own analyses to confirm that the system in the study area did not comply with applicable reliability standards and criteria, and that the GSRP, together with the Manchester to Meekville Junction Circuit Separation Project (MMP) would address those criteria violations. We then used that model to analyze the effect on non-transmission alternatives in addressing the documented criteria violations.

Q. What types of non-transmission alternatives did ICF consider?

A. In assessing the potential for alternative resources to displace or defer the Project, ICF considered three distinct options:

> **Combined Heat and Power Resources (CHP)**: Resources that would typically serve large industrial or commercial loads with both steam and electric power. They are typically the primary source of power for these loads and hence, there is no direct demand from the loads for regional generation resources. This implies that the demand for transmission services to serve such loads is zero, or limited to back-up supply only.
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> **Demand-Side Management Resources (DSM)**: Demand Side Management resources tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source[2].
>
> **Large Scale Generation***:* Large scale generation resources of appropriate sizes located close to the load demand centers may also help reduce the overall load on the transmission system. These include various types of units utilizing alternate types of fuel.

[2] ISO-NE terminology refers to DSM resources as active and passive Demand Response (DR).

These resource alternatives were tested for their effectiveness in either deferring or displacing the upgrades to the existing transmission system while maintaining the same level of reliability, i.e., fully complying with national and regional reliability criteria. The resource quantities were considered to be market-based in the initial analysis. That is, the quantities considered in the initial analysis were based on quantities deemed reasonable to expect given the expected ability of the power market to support the investment requirements associated with the construction and operation of those projects. Thereafter, additional DSM and generation resources, without regard to their economic feasibility, were included in various scenarios that tested the bounds of the ability of non-transmission alternatives to achieve reliability comparable to that provided by the project. In this regard, unlike DSM and large scale generation, the CHP resources included in these subsequent scenarios did not exceed the CHP amounts that were considered economically feasible[3].

Q. **Why did you consider these types of resources as potential non-transmission alternatives to GSRP?**

A. These three types of resources alone, or in combination, have the potential in some circumstances to defer or displace the need for upgrades to the existing transmission system, while maintaining the same level of reliability. However,

[3] Note, ICF did perform a full analysis of the market and the technical potential for CHP and hence has determined both the economic quantity as well as the potential for additional CHP capacity to be installed. In considering additional options over and above those considered economic as non-transmission alternative options, the incremental CHP capacity was not directly considered in part because the incremental quantities were limited, but also in part given the approach for modeling CHP precisely mimicked that for modeling DSM resources in the power-flow cases, such that the total DSM quantities discussed could also be considered CHP resources.

they may not offer the same certainty offered through transmission projects. For example, to provide reliability benefits, active demand resources must be dispatched. Many of these resources can only be called on for short periods of time, and may take 30 minutes or longer to respond, if they do respond. Hence, they do not offer the same certainty as the transmission lines or components which are always present and have a very high availability.

Q. What criteria did you use in evaluating whether these resources, or some combination of them, could provide a practical and feasible non-transmission alternative to GSRP?

A. We evaluated the performance of the potential non-transmission alternatives under the same reliability standards and criteria that govern the New England transmission system. These are the standards established by the North American Electric Reliability Corporation (NERC) and the criteria established by the Northeast Power Coordinating Council, Inc. (NPCC), and ISO-NE.

Q. How did ICF determine what quantities of the different types of resources would be modeled as non-transmission alternatives?

A. We followed two approaches. First, we took a "bottom up" approach, by making aggressive estimates of technically and economically practical new CHP additions in strategic locations; projecting the maximum technically achievable demand-side management additions; and adding new large-scale generation at the electrically most ideal sites for ameliorating the Springfield area problems, without regard to its economic feasibility. In addition, we took a "top down," approach, in which we sought to determine, without regard to technical or economic feasibility, what total amount of demand reductions in the problem areas of Greater Springfield and Connecticut – over and above the previously assumed resource additions – would be necessary to achieve the reliability provided by the GSRP and MMP.

Q. What projected area loads did you use in the power-flow cases you ran to test the hypothetical non-transmission alternatives against the applicable reliability standards?

A. The load projections relied on were from the ISO-NE CELT[4] released in April 2008. The study year considered in the power-flow is 2013, hence we relied on the 2013 projected peak demand under the 90/10 scenario in the ISO-NE CELT report for the base power-flow case and made several adjustments to this.

Q. What adjustments were made to the 2008 ISO-NE CELT 2013 90/10 peak load projections for Connecticut and Western Massachusetts?

A. ICF adjusted the peak load projections for three (3) parameters: 1) reference level CHP projections; 2) DSM penetration; and 3) transmission and distribution losses. **DSM**: First of all, for Connecticut, we assumed in every case the DSM "Focus Case" developed in the January, 2008 Integrated Resource Plan by The Brattle Group, CL&P and UI. Under this assumption, Connecticut DSM resources grow (that is, load is reduced) in total by 134% between 2008 and 2013, reflecting a

[4] "2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission," April 2008, ISO New England.

19% annual average growth in each of the next five years. In addition, for Western Massachusetts, we relied on the results of the first FCA and the show of interest in the second FCA as a basis for determining the DSM projections through 2011, and then applied the same DSM growth rate as in the Connecticut DSM Focus Case to estimate the 2013 DSM. This was an extremely aggressive assumption. The Connecticut Energy Advisory Board, (CEAB) in its *2008 Comprehensive Plan for the Procurement of Energy Resources* (approved Aug. 1, 2008) estimated the cost of the DSM focus case from 2009 through 2014 for Connecticut alone as in excess of $1.6 billion, of which more than $880 million would represent a budget deficit, after application of anticipated revenues from three anticipated funding sources. (Comprehensive Plan, Appendix G). In part for this reason, ICF understands that the Connecticut Department of Public Utility Control declined to approve the DSM Focus Case in its review of the Integrated Resource Plan. (DPUC Review of the Integrated Resource Plan, Final Decision, Feb. 18, 2009, at 46-48).

CHP: CHP penetration projections were performed by ICF based on technical potential and expected market conditions. Within Connecticut, a total of 99 MW were assumed to be active by 2013 while 33 MW were assumed for Western Massachusetts. Since CHP is generally implemented on the distribution side, it was considered as a load reduction for purposes of this analysis.

Losses: The power-flow analysis relies on end-use load as an input and directly solves for transmission and distribution losses. Since the ISO-NE CELT peak load projections reflect energy requirements at the generator, rather than end user level, losses were removed from the CELT projections to characterize the peak load at the end-use level.

Q. Were adjustments to parameters for Connecticut and Western Massachusetts other than load made for the base case?

A. Yes. We identified several generating stations which were not included in the initial ISO-NE needs analysis. These additions reflected units which had been added or were planned to be added since the creation of the original power-flow case. Additionally, units which were projected to be added based on an assessment of capacity requirements using ICF's Integrated Planning Model™ were included. In total, this accounted for 1,184 MW of additional generation in Connecticut and 642 MW of new renewable capacity in western Massachusetts, We also assumed the retirement of some, but not all, units that are currently operating under reliability-must-run (RMR) agreements that terminate beginning in June 2010. These "RMR" units have been identified by ISO-NE as being necessary to ensure system reliability, but they are unable to recover their operating costs under current market conditions. These retirements amounted to 572 MW in Western Massachusetts and 500 MW in Connecticut.

Q. Please summarize for the Council the testing you performed to evaluate demand reduction measures as an alternative to GSRP, and the results of that testing.

A. The total load reductions combined with the generation additions considered in the base case continues to result in system overloads and supported the need for GSRP. As such, we further added incremental zonal load reductions to try to replicate the levels of reliability achieved through the addition of GSRP to the base case. Initially, two additional cases were considered. In our Case 1, we assumed an additional 1,000 MW of load reduction in Connecticut. In our Case 2, we ultimately reduce load in Western Massachusetts by a total of 1,000 MW (about 45% of the peak demand projected for the entire western Massachusetts sub-area in 2013). These reductions were over and above the already aggressive reductions included in the base case.

Q. What were the results of adding these very aggressive DSM assumptions to the power-flow simulation model?

A. Even these reductions failed to resolve all of the Greater Springfield and north-central Connecticut overloads. The following figure (Ex. A-4 in our Report and Figure G-1 in Vol. 1, Section G of the Application), depicts how, even after extreme and unrealistic hypothetical load reductions, the Greater Springfield and north-central Connecticut reliability problems continue to persist in the power-flow modeling.

Number of Distinct Facility Overloads under Contingency Conditions (N-1 and N-1-1) for Various Load Reduction Scenarios

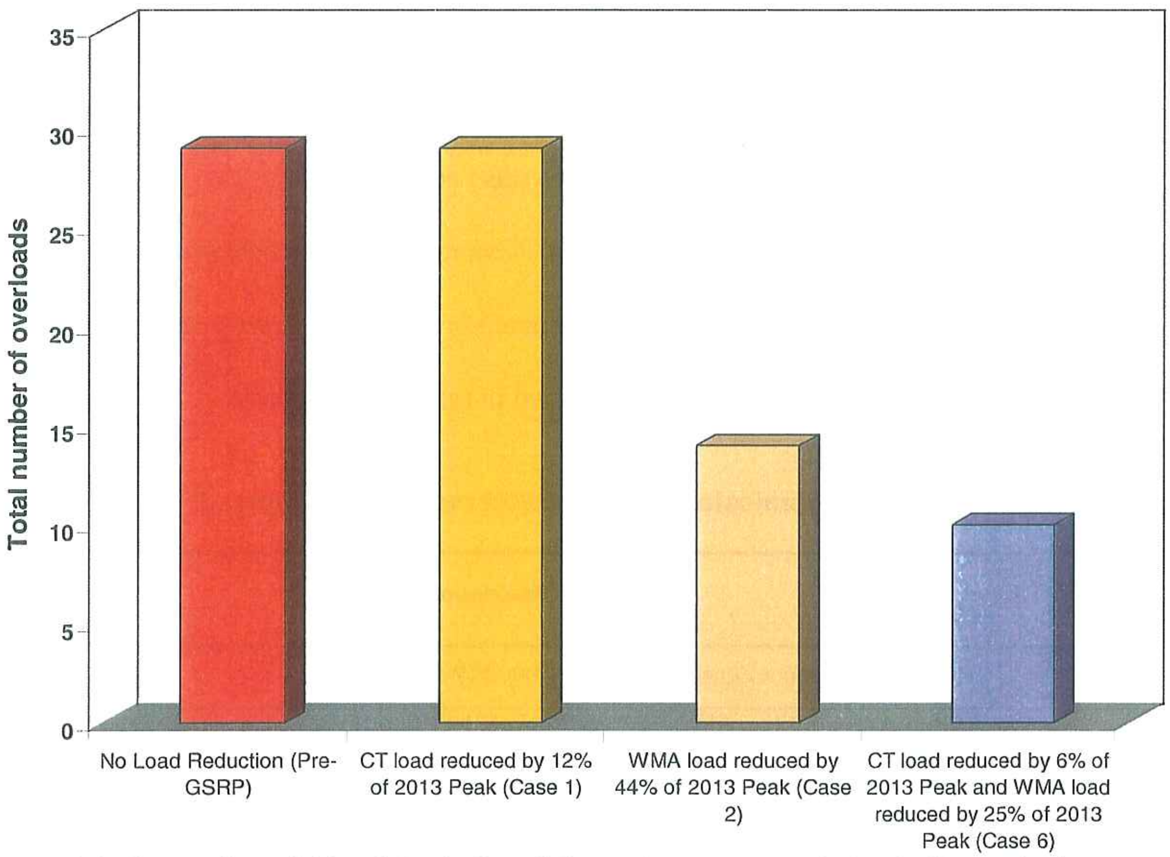

Figure G.1: Greater Springfield and North Central Connecticut area transmission facility overloads as a function of the 2013 Greater Springfield area peak demand projection (bar heights in the chart are approximate). Note that the percent load reduction shown on the graph is in addition to the estimates from the focused DSM case that was modeled in all scenarios tested in the study. Overloads illustrated are for specific dispatch scenarios tested by ICF. Other dispatch scenarios could show additional overloads.

Q. Do the results from modeling extreme DSM reductions provide any information with respect to the likely impact on the overloads of adding more generation resources?

A. Yes, theoretically, the effect of adding generation or reducing load should be similar. So, if reducing load in a particular zone or sub-area by 1,000 MW does not resolve reliability criteria violations, one would expect that adding 1,000 MW of generation would not do so either.

Q. In addition to the DSM scenarios that you have just described, what other specific non-transmission alternatives did you model?

A. We simulated seven different scenarios – five in addition to the two DSM cases just described. Each of these cases assumed variations in supply and demand resources to the 2013 base case, described in the following table:

Non-Transmission Resource Alternatives Simulated[5]

Scenario No.	Description
1	Reduce Connecticut Zonal Demand by 1,000 MWs
2	Reduce Western Massachusetts Zonal Demand by 1,000 MWs which includes specific load reduction in certain substations[6]
3	West Springfield and Berkshire power plants operational and new 400-MWs facility at Berkshire Power (Total of 854 MW in Greater Springfield area)
4	West Springfield and Berkshire power plants operational, new 200-MWs facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 854 MWs in Greater Springfield area)
5	West Springfield and Berkshire power plants operational, new 400-MWs facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 1054 MW in Greater Springfield area)
6	West Springfield and Berkshire power plants operational, reduce CT Zone demand by 500 MWs, and curtail load at Chicopee, Clinton, East Springfield, Agawam, and Breckwood substations
7	Same as Case 6 but with West Springfield and Berkshire power plants unavailable

[5] Exhibit 6-8 in the study report titled "Assessment of Non-Transmission of Alternatives to the NEEWS Transmission Projects: Greater Springfield Reliability Project", Report by ICF Resources, LLC

[6] Specific substations include Chicopee, Clinton, East Springfield, Agawam and Breckwood.

Q. What were the results of these power-flow simulations?

A. None of the modeled non-transmission alternatives – including extreme and infeasible hypothetical scenarios – provided the required reliability.

Q. Have you provided a detailed explanation of all of the assumptions in the power-flow studies that are described in your Report?

A. Yes, these assumptions are set out in the Report itself, and also summarized at pages G-5 – G-8 of the Application.

Q. In your Report, did you estimate the economic costs and benefits of any of the portfolios of non-transmission alternatives that you analyzed, as compared to those of GSRP?

A. No.

Q. Why not?

A. Our assignment was to first determine whether there was a practical and feasible non-transmission alternative or portfolio of alternatives to GSRP and then, only if we determined that there was, to perform an economic analysis of alternative(s) in comparison to GSRP (and the Manchester to Meekville Junction Circuit Separation Project). Since we determined that there was not a technically feasible and practical alternative, we had no occasion to move on to an economic analysis.

Q. In your power-flow modeling, did you include the approximately 700 MW of peaking generation units approved by CTDPUC in its Docket 08-01-01?

A. No, we did not.

Q. Why not?

A. At the time that we began our analysis, the DPUC had not issued its award, and it was uncertain what the award would be. Indeed, since the award was issued, the total number of MW in the portfolio has been reduced by the withdrawal of one plant and the substitution of a smaller plant.

Q. Did this omission materially affect your conclusion that there is no technically practical and feasible non-transmission alternative to GSRP?

A. No. As previously indicated, we determined that reduction of the Connecticut zonal demand by up to 1,000 MW, in addition to the DSM Focus Case, did not resolve the criteria violations. Accordingly, there is no reason to believe that an additional 700 MW of generation would have made a material difference to the results of our Case 1. Moreover, we did assume the addition of the peakers – among many other resource additions and load reductions – in a supplemental power-flow case that we ran at the direction of the CEAB, and even those assumptions left some key criteria violations unresolved.

Q. Please describe the supplemental power-flow case that you ran at the direction of CEAB and its results.

A. After our Report was delivered to CEAB's consultants, LaCapra Associates, we assisted CL&P in responding to several sets of data requests that CEAB and LaCapra submitted concerning the work we had done. After analyzing the Report and our responses to these data requests,. CEAB requested that we run a variant of our "Case 5" by modeling certain assumptions, in addition to those embedded in ICF Case 5. ICF Case 5 starts with the ICF Base Case, which includes the resources assumed in the ISO-NE needs analysis plus:

33 MW	new CHP capacity in Western Massachusetts
99 MW	new CHP capacity in Connecticut
1184 MW	new generation in Connecticut
508 MW	"focus" DSM in Connecticut
225 MW	passive DR in Western Massachusetts
642 MW	new hypothetical renewable generation in Western Massachusetts.

The ICF Case 5 further adds:

600 MW	new hypothetical generation in the Springfield area and, re-activates
304 MW	Springfield generation previously assumed to be retired in the reference case.

The additional assumptions dictated by CEAB were:

1500 MW	additional new generation in Connecticut curtails 350 MW
350 MW	from curtailment of exports to Long Island on the Cross Sound Cable and,
1800 MW	reduction of the Connecticut Import from 2500 MW to 700 MW

Thus, the input assumptions for the additional power-flow case include the resources in the ISO-NE needs assessment plus:

33 MW new CHP capacity in Western Massachusetts
99 MW new CHP capacity in Connecticut
2684 MW of new generation in Connecticut
508 MW of "Focus" DSM in Connecticut
225 MW of passive DR in Western Massachusetts
642 MW of new hypothetical renewable generation in Western Massachusetts.
350 MW from curtailment exports on the Cross Sound cable
600 MW of new hypothetical generation in the Springfield area and,
304 MW from re-activation of Springfield generation previously assumed to be retired.

Even with these assumptions, key overloads that drive the need for GSRP remain. These overloads are identified in the power-flow case results that I understand have been filed with the Council and provided to qualified parties and intervenors under a CEII protective order in response to Q-OCC-012.

Q. **Did ICF perform any evaluations that specifically considered the proposed Meriden generating plant?**

A. No. All of our work was done before the Meriden Plant was proposed in response to the CEAB Request for Proposal for alternative projects.

Q. **Do the ICF study and Report provide pertinent information concerning the potential of the Meriden Plant to achieve the same compliance with national and regional reliability standards as GSRP does?**

A. Yes. The Meriden Plant would add 530 MW of generating capacity in Connecticut. Our power-flow studies demonstrated that far greater resource additions or load reductions in Connecticut would be insufficient to resolve the many violations of reliability standards and criteria in Greater Springfield and north-central Connecticut. It is apparent from these results that the Meriden Plant would not achieve such compliance either.

Q. It has been suggested that the Meriden Plant could resolve the reliability criteria violations addressed by GSRP and MMP because it could displace imports over the tie lines between Western Massachusetts and Connecticut. Does the supplemental power-flow that you executed at CEAB's direction provide any information pertinent to that suggestion?

A. Yes. Although the Connecticut import was reduced by 1800 MW – a reduction in load crossing the interface far greater than the capacity of the Meriden Plant – overloads on the Massachusetts system persisted. This illustrates that adding generation in Connecticut to enable a reduction in the Connecticut-Massachusetts transfer would not provide a reliability benefit equivalent to that of the GSRP and MMP.

Q. Did ICF consider transmission alternatives to GSRP?

A. No. This was not part of the scope of work which ICF was engaged to perform.

Q. Please summarize the conclusions of the analysis.

A. In conclusion, based on the detailed technical analysis of non-transmission alternatives available for the GSRP project, I find that the feasibility of any options available are not realistic or reasonable in nature and hence do not offer themselves as NTA solutions. That is, no satisfactory NTA solutions are considered to be available for the GSRP project.

Q. Does ICF continue to support the conclusion of the GSRP NTA performed in 2008 analysis that no reasonable alternatives to the GSRP project exist?

A. Yes.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF CONNECTICUT

SITING COUNCIL

The Connecticut Light and Power Company application for Certificates of Environmental Compatibility and Public Need for (1) The Greater Springfield Reliability Project consisting of a new 345-kV electric transmission line and associated facilities from the North Bloomfield Substation in Bloomfield to the Connecticut/Massachusetts border, together with associated improvements to the North Bloomfield Substation, and potentially including portions of a new 345-kV electric transmission line between Ludlow and Agawam, Massachusetts that would be located in the Towns of Suffield and Enfield, Connecticut; and (2) and the Manchester Substation to Meekville Junction Circuit Separation Project in Manchester, Connecticut.	:	Docket No. 370: CT Valley Electric Transmission Project and
NRG Energy, Inc. application pursuant to C.G.S. § 16-50*l*(a)(3)	:	Docket No. 370B
	:	**July 7, 2009**

WRITTEN DIRECT TESTIMONY OF JULIA FRAYER,

ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY

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DIRECT TESTIMONY OF JULIA FRAYER

1 Introduction

Q. Please state your name and business address.

A. My name is Julia Frayer, and I am one of the partners and a Managing Director of London Economics International LLC ("LEI"). My business address is 717 Atlantic Avenue, Suite 1A, Boston, MA 02111.

Q. Please summarize your relevant professional background.

A. As Managing Director of LEI, I currently direct many of the company's engagements involving economic analysis, simulation modeling, asset valuation, price forecasting and market design.

I have been actively engaged in New England power market-related work since prior to commencement of ISO-NE market operations, having assisted potential buyers in the due diligence of various generation asset sales in the mid to late-1990s. I have closely followed the evolution of the New England power markets, from the days of uniform pricing to conversion to Locational Marginal Pricing with Standard Market Design, as well as the revolutionary changes in the adoption of the Forward Capacity Market, in lieu of the Installed Capacity mechanism.

With restructuring proceeding across the US in the late 1990s and early 2000s, the question of economic value of transmission arose. And in 2003, LEI was engaged to assist the California ISO ("CAISO") in creating a new framework for evaluating the economics of a proposed transmission investment – one of the first efforts of any US-based ISO to consider the economics of transmission investment. I co-led this project, managing a number of subcontractors and a very diverse stakeholder group, consisting of the California investor owners utilities ("IOUs") CAISO staff, regulators, and other industry representatives. In conjunction with the CAISO's transmission planning department and the Department of Market Analysis ("DMA"), I created a multi-dimensional economic framework for evaluating the implications of new transmission on power markets, taking into account the potential for productive efficiency gains, competitive effects, and explicitly considering the impact of uncertainty in evaluating the economics of transmission. I also proposed a method for measuring the value of embedded real options with the investment. The CAISO continues to use a variant of our proposed framework, referred to as the "TEAM" method, in its planning and regulatory process.

I have also worked with Connecticut stakeholders in the past and testified before the Department of Public Utility Control. In 2004 and 2005, I monitored the transitional standard offer Requests for Proposals ("RFPs") issued by Connecticut Light and Power. I submitted affidavits to the Department in conjunction with the conclusion of these RFPs. Subsequently, I was engaged by the Connecticut Department of Public Utility Control ("DPUC") to design, administer and independently evaluate the 2006 RFP for New or Incremental Capacity. As part of this project, I presented written testimony and participated in hearings at the DPUC.

My recent projects in New England included advising the Maine Public Utility Commission in the implementation of legislation that required a competitive solicitation for long term contracts.

Over the last ten years, I have also been actively advising private investors, including institutional investors, lenders, and project developers on the economic value of generation assets in deregulated power markets across the US, Canada, and abroad. I have also provided economic advisory services to project sponsors of several proposed inter-jurisdictional transmission projects.

For further details, my resume is included in the Resume Volume submitted by the Connecticut Light and Power Company ("CL&P").

Q. What is the purpose of your testimony?

A. I was engaged by an affiliate of CL&P, Northeast Utilities Service Company ("NUSCO"), to perform an economic analysis of Greater Springfield Reliability Project ("GSRP").

Operating subsidiaries of NUSCO and National Grid US have proposed four reliability transmission projects, referred to as the New England East-West Solution ("NEEWS"). The four projects include: Rhode Island Reliability Project ("RIRP"), followed by the Greater Springfield Reliability Project ("GSRP"), and then the Interstate Reliability Project ("Interstate"), and finally the Central Connecticut Reliability Project ("CCRP"). These transmission projects involve reinforcement of the New England transmission system in and around Connecticut, Massachusetts and Rhode Island, in order to solve identified system security shortfalls within the transmission system. These four projects are therefore being proposed to achieve compliance with reliability requirements, and not primarily "economics-oriented" project. Nevertheless, these transmission projects may yield ancillary economic impacts, as I discuss further below with respect to GSRP.

As a result of the transmission reinforcements planned with each of the four projects in NEEWS, the total transfer capability of key transmission interfaces within New England would increase. The increase in transfer capability will allow the New England Independent System Operator ("ISO-NE") to more efficiently and effectively operate the system and wholesale power market. NEEWS can thus create economic benefits to supplement the reliability benefits for which it was designed.

I was asked to measure these potential economic benefits that may accrue to New England electricity consumers for each phase of NEEWS. I was also asked to evaluate and project the impact on emissions and system performance. By its nature, this was a forward-looking analysis. The forecast timeframe covered a ten-year timeframe[1], 2014-2023, based on a notional commercial operation date of 2014 for the NEEWS projects. My testimony specifically focuses on the economic impact of GSRP.

I do want to note upfront that my analysis was limited to the ISO-NE wholesale markets; therefore, I did not analyze secondary and tertiary effects that GSRP may create through its impact on labor and other service markets, tax receipts, etc. In addition, although I had to make assumptions on new generation and transmission developments, the study should not be viewed as an integrated resource plan.

Q. What kind of analysis did you perform?

A. In order to isolate the economic benefits of GSRP, I modeled the RIRP project as the baseline and then included the GSRP to capture the benefits of GSRP. I employed proprietary simulation models tailored to ISO-NE Market Rules to forecast market outcomes in the ISO-NE hourly spot market for energy, the locational forward reserve market ("LFRM"), and the FCM. Appendix A contains a description of the modeling tools I applied in this study.

I began with a Base Case analysis, which represented the most likely set of conditions for a ten-year period starting with 2014, including a market-based forecast for fuel costs, the ISO-NE's 50/50 demand forecast from RSP 2008, existing supply resources, and a balanced, yet pragmatic, economics-driven retirement schedule and generation build out such that Installed Capacity Requirement ("ICR") forecast levels are achieved in the long run, and the New England states' Renewable Portfolio Standards ("RPS") goals are met. My assumptions were developed through vigorous analysis of

[1] The ten-year modeling timeframe provided for a reasonable timeframe for estimating and characterizing the benefit streams from GSRP. Although I recognize that the economic life of GSRP is much longer and that there are going to be benefits attributable to GSRP after 2023, I did not believe it was useful to complete the modeling for a longer time period because the results would be subject to a larger (and escalating) forecast error because of increased uncertainty in key inputs and assumptions the further one looks in time. Modeling results would not be very reliable over much longer periods of time.

potential market conditions and the best available information as of the fall of 2008, when the modeling analysis began.[2] Appendix B contains a summary of the Modeling Assumptions employed in my analysis.

In addition, I tested several scenarios with different assumptions to capture possible outcomes given a change in circumstances from the Base Case assumptions. For example, I studied a 'High Fuel Prices' scenario, a nuclear outage scenario, as well as a scenario that considered additional retirements in Connecticut, moderated with more renewables in Northern New England. I also ran a sensitivity using ISO-NE's 90/10 demand projections.

Q. How did you capture the benefits of GSRP?

A. The economic modeling allowed me to forecast the annual market prices with each project. These market prices were next used to calculate the total costs to load. Total economic benefits for the GSRP project are then equal to the reduction in costs to load. It is calculated by subtracting total market costs to load under RIRP-only (our baseline) from the total market costs to load under GSRP. Market benefits accrue if prices (or procurement/consumption quantities) decline.

Q. What did you conclude from your economic analysis of GSRP with respect to the energy market?

A. New England ratepayers can expect energy market benefits attributable to GSRP over ten-years to average $35 million per year under the "normal" operating conditions modeled in the Base Case. These are regional market benefits, and not limited to a single load zone. At the upper bound of the 95% confidence level, the cumulative, ten-year benefit stream may be as high as $404 million in nominal terms. The figure below

[2] In order to ensure that our supply figure has captured the most current market information regarding future generation, I updated the short term new entry analysis so that it is up-to-date as of April 2009 for I.3.9 status of known generation projects in the ISO-NE Interconnection Queue, and for the results of the second FCA from February 2009.

provides a summary of the distribution of the ten-year energy market benefits for GSRP in the Base Case. In section 2 of my testimony I discuss these results in greater detail.

Figure 1. Ten-year cumulative sum of projected energy benefits for GSRP in Base Case across different confidence intervals (nominal $ millions)

Energy market benefits, 2014-2023 (nominal $ millions)	
95% Upper	$403.7
90% Upper	$394.6
80% Upper	$384.4
70% Upper	$377.7
60% Upper	$372.4
Mean	$350.0
60% Lower	$327.6
70% Lower	$322.3
80% Lower	$315.5
90% Lower	$305.4
95% Lower	$296.3

In my opinion, these are very conservative estimates. The Base Case modeling understates the potential range of economic benefits of transmission by explicitly focusing on 'normal' or weather-normalized load conditions. The economic value of transmission is much higher under periods of system stress. The energy benefits I discuss in this testimony are limited to a ten-year modeling timeframe, but there will inevitably be more benefits after 2023 that I have not quantified. All the modeling assumed perfect competition. Therefore, in the energy market, forecast prices were based on short-run marginal costs. Transmission has been recognized as a source of competitive market discipline, because it naturally expands the scope of competition in a given market. Hence, if the modeling had moved away from perfect competition assumptions, economic benefits for ratepayers could have been larger. Lastly, the Base Case modeling assumptions also effectively create an uncongested ISO-NE market; therefore, the benefits of GSRP due to congestion relief are minimized in the model.

Indeed, much higher energy market benefits are possible under certain market conditions, as summarized in the figure below. These results highlight the insurance value of GSRP – GSRP serves as a "hedge" against higher market costs due to unexpected events. For example, under the situation of a nuclear plant outage in Connecticut, GSRP produces a maximum energy market benefit for New England ratepayers equal to $332 million based on an annual average basis.[3] In other words, one year of market benefits under such a situation would cover almost half of the $714 million estimated cost of the project.

In addition, confidence intervals were constructed at the 95 percent confidence level over three years for the nuclear outage. This range demonstrated the likely range a three-year average will fall between, given different outage and maintenance schedules. Accounting for how the system reacts to these stochastic shocks, the confidence interval informs us that the likely annual benefit is mostly likely to fall between $291 and $372 million dollars.

Figure 2. Nuclear outage scenario results for three selected years

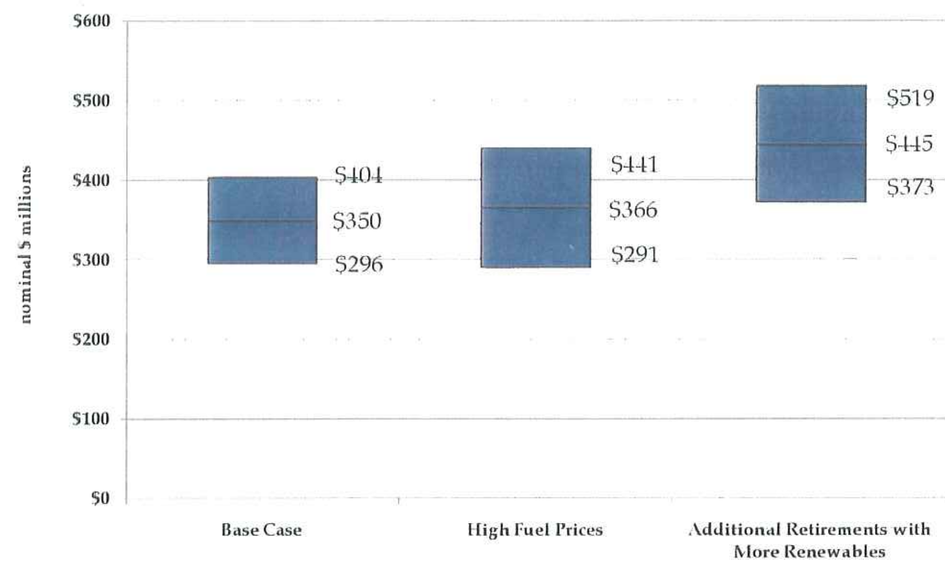
nominal $ millions	95% CI Lower Bound	Three-year Average*	95% CI Upper Bound
Nuclear Outage	$ 291.4	$ 331.9	$ 372.4

* The selected years are 2014, 2018 and 2022

GSRP can also shield consumers against some of the cost increases due to higher gas and oil prices. GSRP also complements environmental goals and provides transmission access for the imports of low cost renewables from other parts of New England. In addition, during periods of high demand, GSRP may in fact prevent local system interruptions in Connecticut (and I have conservatively used a relatively "low" value for the opportunity costs of such system interruptions). The figure below summarizes the range of ten-year benefits under a 95% confidence interval from the energy market across the scenarios modeled over this timeframe. The results of each scenario are discussed in more detail in Section 2 of my testimony.

[3] The average is calculated based on three selected years, which are 2014, 2019 and 2022.

Figure 3. Ten-year cumulative sum of projected energy benefits of GSRP across modeled scenarios*, 2014-2023 (nominal $ millions)



** Note: the nuclear outage case results are for a single year, because that scenario was simulated for three sample years rather than for ten consecutive years. The other scenarios are for a ten-year period.*

Q. Is GSRP expected to create benefits in the LFRM or FCM?

A. GSRP is expected to create economic benefits of $5.5 million per annum on average in the LFRM. In contrast to the energy market benefits, which are created solely through price reductions, much of the beneficial impact on LFRM is driven by changes in the quantity (or volume) of locational reserves. Based on the results of the energy modeling, I projected that the Connecticut reserve zone's Locational Forward Reserve Requirement ("LFRR") would decline by approximately 195 MW as a result of GSRP (due to the additional transmission capacity on the CT Import interface). This reduction in LFRRs would create benefits for all ratepayers in New England – not just to Connecticut ratepayers. There is substantial precedent for such an outcome with respect to transmission upgrades and LFRR reductions. In 2007, with the completion of the NSTAR 345-kV upgrades, ISO-NE reduced LFRRs in the Boston reserve zone.[4] And ISO-NE has

[4] 2007 ISO-NE Annual Markets Report, p. 82.

already forecast that in 2010, it expects the LFRRs in the Southwest Connecticut reserve zone to drop, as a result of the SWCT Phase II project.[5]

In the FCM, GSRP can also create benefits for Connecticut ratepayers. In the first two Forward Capacity Auctions that have taken place, Connecticut was not designated an import-constrained zone.[6] Going forward, based on the ISO-NE projected Connecticut LSR (with NEEWS or without NEEWS) and LEI's projections for Connecticut supply, Connecticut is not expected to become an import-constrained zone under the Base Case.[7] Nonetheless, the additional transmission capacity created by GSRP on the Connecticut import interface will serve to reduce the likelihood (or at least defer the potential) that Connecticut would be designated an import-constrained zone if market conditions evolve differently from Base Case expectations. ISO-NE has recognized this benefit implicitly in recognizing that NEEWS is expected to decrease the Local Sourcing Requirement ("LSR") applied to Connecticut. There is some positive economic benefit for ratepayers from this "insurance", as capacity zone designation could mean a higher capacity clearing price. However, I have not attempted to quantify this value, as my Base Case is created around the ISO-NE forecasts and Connecticut is expected to stay part of the "rest of Pool" under such assumptions.

In terms of other direct impacts on the FCM, I do not believe they are likely. NEEWS, generally, and GSRP in particular, are viewed by market participants as a reliability-driven transmission project. The energy market benefits I describe above are

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[5] ISO-NE, 2008 RSP, p. 55.

[6] Informational Filing for Qualification in the Forward Capacity Market, page 3, ISO-NE, Docket No. ER08-1513-000 (September 9, 2008), http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf and Informational Filing for Qualification in the Forward Capacity Market, page 4, ISO-NE, Docket No. ER08-190--000 (November 6, 2007), http://www.iso-ne.com/regulatory/ferc/filings/2007/nov/er08-190-000_11-06-07_informational_filing.pdf

[7] ISO-NE has published a forecast for Connecticut LSR through 2016 in the December 17, 2008 PAC meeting. "Resource Adequacy Analysis", slide 20 and slide 21, ISO-NE, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/dec172008/a_resource_adequacy.pdf. LEI extrapolated that forecast for the period after 2016. Under Base Case conditions, LEI does not expect Connecticut to become an import-constrained zone over the modeling horizon.

created as a result of fairly small changes in energy prices. Although lower energy prices can impact generators' profits, and generators' expectation of profits should conceptually flow through into their capacity market bids, I believe that the expected energy price reductions from GSRP are too small to substantially affect bids in the Forward Capacity Auctions ("FCA"). GSRP – as a reliability-driven transmission project - is not a substitute for generation. Moreover, the profit impact from GSRP's energy price reductions is likely to be very small – less than 10 cents per kW-month for a typical combined cycle gas-fired plant. Generators face much greater uncertainties from other market drivers and therefore in reality are unlikely to consider GSRP's future energy market impacts in the development of their FCA bid. In conclusion, I did not attribute any FCM impacts to GSRP.

Q. Please summarize your Base Case projections of economic market benefits for New England and Connecticut ratepayers?

A. Under the Base Case, the forecasted 95% confidence interval for the total cumulative ten-year benefits from the energy market and LFRM is equal to $351 million to $459 million in nominal terms. When we compare these benefits to costs, the benefits and costs must be denominated in the same dollar terms. I have converted the cumulative ten-year sum into a present value sum of benefits using a 10% discount rate. Therefore, the present value ("PV") of this ten-year energy and LFRM benefit stream in 2014 dollar terms ranges from $217 million to $287 million with a 95% confidence.

This is the market-wide impact and therefore the benefit to all New England ratepayers. This is the relevant benefit figure to apply in an analysis of GSRP because the costs will also be borne by all New England ratepayers. GSRP is expected to be designated a pooled transmission facility ("PTF") and therefore the costs of GSRP will be shared by all New England ratepayers.

Based on the load forecasts I have used, Connecticut ratepayers will be responsible for approximately 25%[8] of the costs of GSRP, or approximately $180 million of the $714 million total investment costs. Given the projected energy price reductions in Connecticut in combination with Connecticut load and the application of the Market Rules for the settlement of the LFRM charges, Connecticut ratepayers will receive a ten-year PV benefit stream in the range of over $54 million to nearly $72 million with a 95% confidence (at a 10% discount rate). In summary – although GSRP is a reliability-driven project – it is likely to generate energy and LFRM benefits for Connecticut ratepayers that cover as much as 40% of the investment costs under the Base Case. Under the other scenarios considered, the projected economic benefits contribute even more towards investment costs and may even exceed them under certain circumstances.

Q. Did you perform any other analysis for NU?

A. Yes, subsequent to our initial modeling of GSRP, NUSCO asked that I re-run the simulation models to measure the potential economic impact of the Meriden project on ISO-NE wholesale power markets, using the same set of assumptions and methodologies as applied to the GSRP analysis under the Base Case.

Q. What did you conclude from your economic analysis of the Meriden project?

A. Overall, my Base Case simulation modeling and analysis of Meriden's expected benefits and costs for Connecticut ratepayers suggests that in some years between 2014 and 2023, the projected contract costs of Meriden would be greater than the projected benefits of Meriden. The net benefits (benefits less costs) are going to be marginally positive on a PV basis[9] over the ten-year modeling timeframe. If I exclude the less certain impacts of the LFRM and the FCM, the net benefits are below zero on a PV basis. In other words, although Meriden may create market benefits by lowering market prices for Connecticut

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[8] http://www.iso-ne.com/pubs/pubcomm/forums/2009/tca_stakeholder_mtg_jan292009/1_iso_tca_overview_final.ppt#312,13,Regional

[9] Using a 10% discount rate

ratepayers, those benefits may be less than the contract costs such that Connecticut ratepayers will end up paying under a 'contract for differences' structure. Section 3 contains a more detailed discussion of the Meriden analysis.

Q. How did you estimate the costs of Meriden?

A. I assumed that Meriden would be developed under a long-term contract, as emphasized by Meriden in its application to the CSC. More specifically, I estimated annual contract payments to Meriden under a "contract for differences" structure.[10] In my estimates, I first established the annual gross contract payment to Meriden based on the stipulated investment costs, a ten-year contract term, and estimated fixed O&M costs. I then identified the projected operating profits from the energy market per the energy market simulations and the projected capacity revenues[11], per the capacity market modeling. The income from these two revenue streams was deducted from the gross contract payment to yield a net annual contract cost.

Q. Please describe your market benefit analysis for Meriden.

A. Connecticut ratepayers would be responsible for the entire costs of the Meriden contract – in contrast to the "socialization" of costs of transmission. Therefore, for consistency, I examined Meriden's impact on costs to load from energy, LFRM, and FCM from the Connecticut ratepayers' perspective.

Consistent with market intuition, Meriden is projected to reduce locational marginal prices ("LMPs") in Connecticut. In the initial years of operation, LMPs decline by more than $2/MWh on an annual demand-weighted basis. However, these energy benefits are expected to decline with time, because of the generation response that will inevitably occur: Meriden will delay or forestall other new generation investment, and

[10] Connecticut Energy Advisory Board Evaluation Report to the Connecticut Siting Council, p.39

[11] Net of Peak Energy Rent (PER) adjustments

possibly compel some retirements. After approximately three to five years, the ISO-NE system would re-balance itself and the basis for price reductions would slowly dissipate.

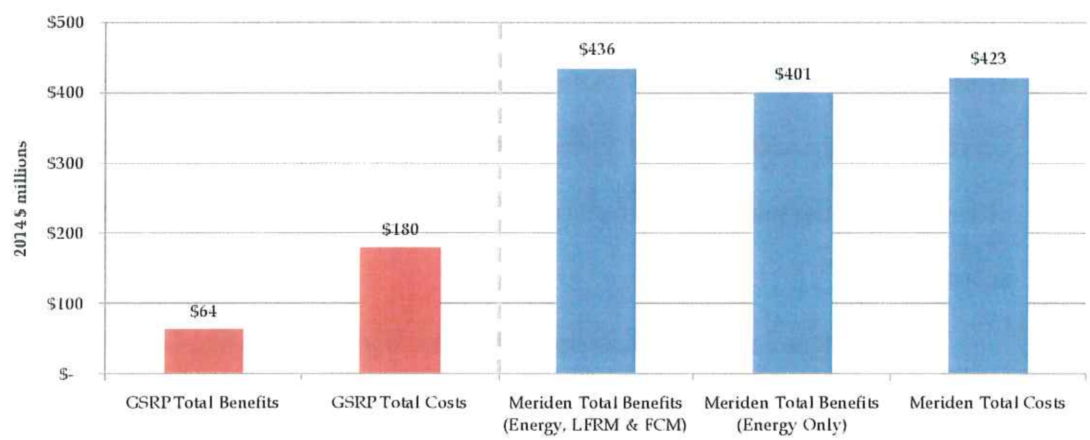
Meriden could also create some LFRM benefits indirectly by reducing the opportunity costs of reserve provision. I explicitly take this into consideration. In contrast to the energy market, Meriden may produce dis-benefits in the initial years, or increased FCM costs. LMP reductions will lead to lower energy profits, which I refer to as the "income effect." In this instance, the income effect will outweigh any "substitution effects" created by the addition of more capacity (which shifts out the capacity supply curve, and should, ceteris paribus, lower FCA prices). The relative size of the income effect vis-à-vis the substitution effect causes FCA prices to rise, and dis-benefits to accrue.

Furthermore, unlike a reliability-based transmission project like GSRP, other generators would view Meriden as a competitor. And, in contrast to the impact of GSRP on generator's profitability and bidding in the FCM, Meriden would create a more substantial impact on profitability. Moreover, relative to transmission enhancements, generators would be in a better position to anticipate the effect of new competition. Therefore, I believe that suppliers would be taking into account the effect of Meriden in their bidding behavior in the FCM and the estimated FCM dis-benefits are plausible.

Q. Can you please compare the net benefits of Meriden versus GSRP from the perspective of Connecticut ratepayers?

A. Figure 4 below shows the comparison of benefits and costs for Connecticut ratepayers from GSRP versus Meriden. GSRP is projected to create on average $64 million total benefits for Connecticut ratepayers over ten-years (PV basis) which is covering a substantial portion of Connecticut share of the investment costs of GSRP. Again it is important to emphasize that GSRP is a reliability-driven project. On the other hand, the total market benefits from Meriden under the Base Case are estimated at about $436 million in PV terms over ten years, and the total contract costs from Meriden are $423 million yielding positive net benefits. However, if the FCM and LFRM market impacts are excluded, Meriden's benefits forecast falls to $401 million in 2014 dollar terms and below projected costs, which create positive benefits of nearly $13 million for Connecticut ratepayers.

Figure 4. Comparison of present value of benefits and costs for CT ratepayers from GSRP versus Meriden (2014 $ millions)



Note: (1) GSRP total benefits include energy and LFRM market benefits pro rata to Connecticut.

(2) GSRP total costs equal to the total investment cost of GSRP $714 million multiplied by the forecast load of 25%, pursuant to ISO-NE's transmission cost allocation methods.

(3) Meriden total benefits include energy, LFRM and FCM market benefits procured to Connecticut.

(4) Meriden total costs include total contract costs net of energy and FCM offsets.

2 Economic Analysis of the GSRP

Q. What kind of energy modeling was performed?

A. The analysis involved detailed hourly simulation modeling of future power market conditions for ten years. As described further in Appendix A, POOLMod – the simulation model used in this analysis – approximates the ISO-NE commitment and dispatch routines from their security constrained economic dispatch ("SCED") model. Similar to ISO-NE's LMP algorithms, POOLMod determines a market-clearing price based on the most economic (and technically feasible) set of resources needed to meet the hour's demand, taking into account binding transmission constraints. The offer price of resources was derived from estimated short run marginal costs, which include unit-specific fuel costs (monthly fuel prices multiplied by each unit's heat rate), variable operations and maintenance costs ("VO&M") and the costs of emissions allowances (SO_2, NO_X, and CO_2). The assumptions underlying these variables are described in Appendix B to this testimony.

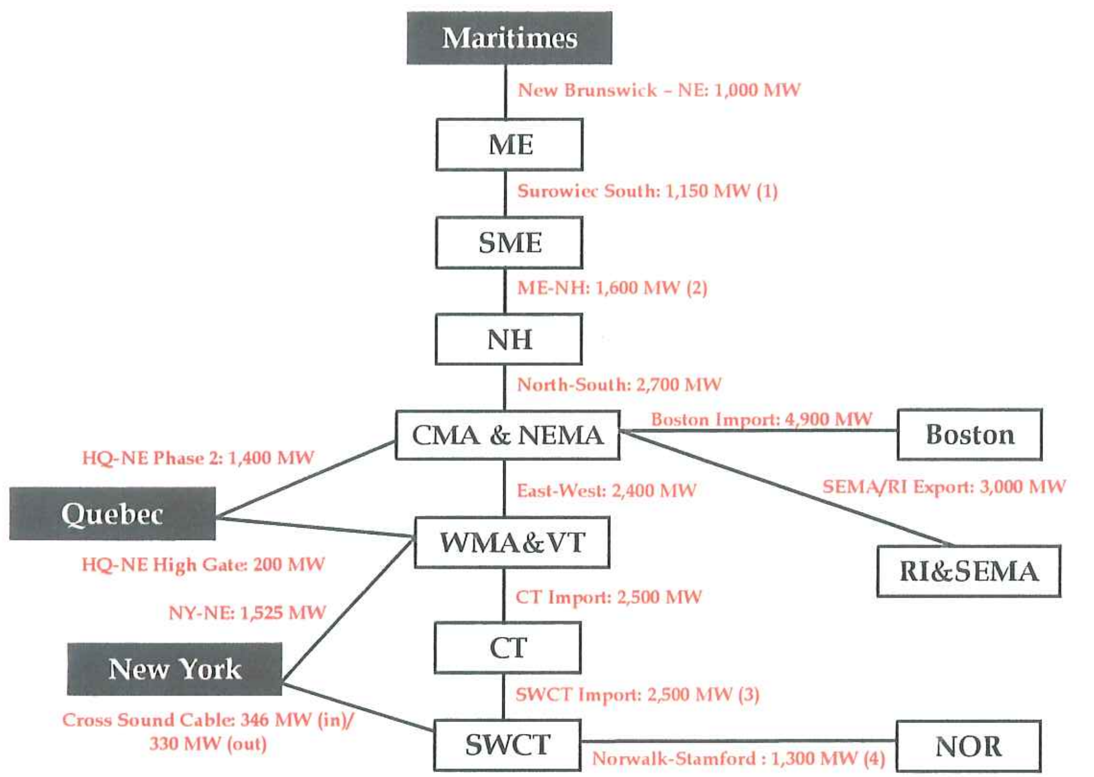
Q. Were transmission constraints considered in the modeling?

A. Yes, the thermal transfer limits of the major internal interfaces on the ISO-NE system were explicitly considered in the modeling.[12] Energy flows across the interfaces were monitored. Generation was dispatched such that flows did not exceed the thermal transfer limits. When necessary, re-dispatch of generation to achieve compliance with the thermal

[12] Sources: Limits for the Connecticut Import and New England East-West interface were provided by Northeast Utilities; the capacity upgrades for the Suroweic South interface is taken from the Federal Energy Regulatory Commission Order on Conditionally Granting Petition for Declaratory Order issued on October 20, 2008. The assumptions for the remaining transmission limits are based on the information used by ISO-NE in recent analysis on the Maine Power Connector, presented May 22, 2008 at ISO-NE by Wayne Coste. http://www.iso-ne.com/committees/comm_wkgrps/othr/econ_stdy/mtrls/2008/may222008/mpc_economic_analysis_preliminary_5_22_2008.pdf.

transfer limits created the locational differences in market-clearing prices. The figure below provides an overview of the transmission topology considered in the energy market simulations.

Figure 5. New England system topology modeled under the Base Case



Note:

(1) Suroweic South: Increases to 1,875 MW in 2013

(2) Maine to New Hampshire Interface: Decreases to 1,575 MW in 2011; Decreases to 1,550 Mw in 2012; Decreases to 1,525 Mw in 2013; Decreases to 1,500 MW in 2014; Decreases to 1,475 MW in 2015; Decreases to 1,450 MW in 2016

(3) SWCT Imports: Increases to 2,700 MW in 2010

(4) Norwalk-Stamford: Increases to 1,650 MW in 2010

Regions: ME=Maine; SME=Southern Maine; NH=New Hampshire; CMA&NEMA=Central Massachusetts and Northern Massachusetts; WMA&VT=Western Massachusetts and Vermont; BOSTON= Boston; CT=Connecticut; SWCT = Southwest Connecticut; RI&SEMA=Southeastern Massachusetts and Rhode Island; NOR= Norwalk

In addition, marginal transmission loss factors were also included in the calculation of energy prices, consistent with ISO-NE's LMP formulations and transmission loss factors.

Q. How was GSRP modeled?

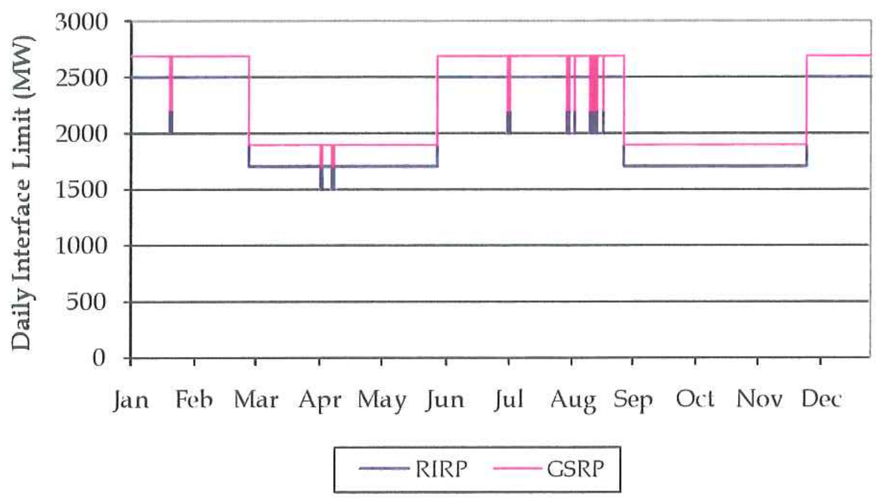
A. GSRP was represented in the modeling as an increase in the thermal transmission capacity on both the Connecticut Import and the East-West interfaces. In general, GSRP is expected to increase the thermal transfer capability of both the Connecticut Import and East-West interfaces by approximately 200 to 300 MW, but to be conservative, I modeled a gross increase of 200 MW. In addition, several adjustments were made to the transmission limits. To capture seasonality, the interface limits for the CT Import and East-West interfaces are modeled dynamically hour to hour depending on the season; this approximates the reduced transfer limits in shoulder periods due to the typical timing of transmission system maintenance outages. The interface limits for such contingencies were adjusted according to operating levels observed by Northeast Utilities ("NU") staff: the basic CT Import limit of 2,500 MW/2,700 MW (under RIRP/GSRP) was reduced by 800 MW for the spring (months of March - May) and fall (months of September – November periods). NU staff also provided LEI with more detailed interface assumptions to include in the modeling with respect to the CT Import interface:

- the Connecticut Import limit was also reduced by 500 MW when the New York exports (excluding Cross Sound cable) are more than 1,000 MW or when the New York imports (excluding Cross Sound cable) are more than 1,300 MW in a given hour; and
- both the Connecticut Import and the East-West interface limits were reduced by 500 MW whenever all Lake Road units are modeled out-of-service.

These reductions (including the seasonal maintenance outages) were additive if a combination of the above conditions existed, with the maximum reduction of 1,000 MW at a single time for the limit of the CT Import interface.

The figure below demonstrates the types of adjustments made to the transmission limit levels for the CT Import interface. The interface limits are plotted on an hourly basis for the entire year. The graph shows that the CT Import Interface is reduced in both the summer and spring by 800 MW. In the fall, the New York export or import levels triggers another 500 MW reduction in the interface limits, the full 500 MW reduction is taken since the 1,000 MW maximum derate threshold has not been met.

Figure 6. Illustration of adjusted interface limits for the CT Import interface



Note: Results are for a single iteration.

Q. What was the source of inputs into POOLMod?

A. POOLMod was populated with input data from various industry sources, including ISO-NE (the modeling relied on data from the 2008 Regional System Plan ("RSP"), the 2008 Capacity, Energy, Load and Transmission ("CELT"), the 2007 Annual State of the Markets, etc.), NERC data (GADS data for plant operating parameters), FERC data (such as FERC Form 423 for historical fuel prices, FERC Form 1 for production costs), Energy Information Administration ("EIA") data (such as the 2008 *Annual Energy Outlook*), Environmental Protection Agency's data from the Continuous Emissions Monitoring system ("CEMS"). Market price data was also gathered from Bloomberg (for determining future fuel prices and emission allowance prices).[13]

Q. Were all existing resources in New England's control area modeled?

A. Yes, I considered all existing resources. For reference, the figure below presents a map of all generating resources in ISO-NE's control area by fuel type and relative size. In our modeling, pre-existing (i.e., currently operating) demand response resources that have already qualified at ISO-NE for treatment as a capacity resource were also included. In addition, new, qualified demand-side resources from recent FCAs were included in the modeling in future years. For example, in the most recent FCA held in February 2009, over 2,900 MW of demand-side resources cleared for the 2011-2012 capability period (of which, 453 MW were essentially "new" demand resources that had not previously participated in the FCM).[14]

Given the operational concerns regarding performance requirements that have been raised over the last year, I believe that only a portion of these new demand-side resources will remain in the market over the longer term, especially if capacity prices decline below levels at which demand-side resources are willing to curtail load. It is anticipated that only 40-60% of the new demand-side resources will be able to remain permanently involved given the performance requirements and low levels of

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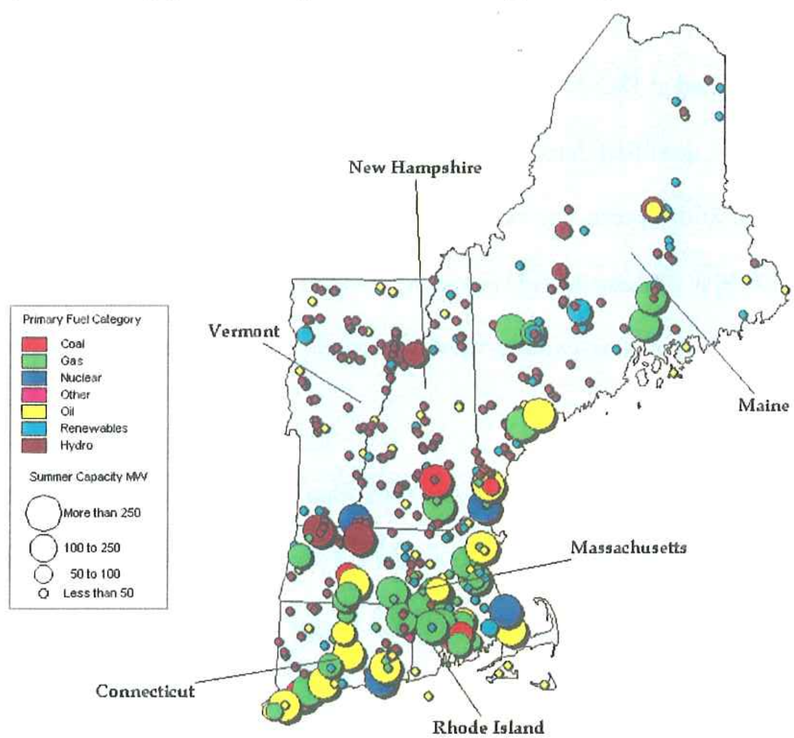
[13] Some of the data mentioned above, for example, EIA Form 411 and CEMS data were directly obtained from Ventyx, the Velocity Suite. Ventyx, the Velocity Suite is widely and routinely used by consultants, energy companies, and other market participants in the sector. It provides a valuable data service by compiling raw data from a variety of primary data sources (for example, Federal Energy Regulatory Commission ("FERC"), US Energy Information Administration ("EIA"), North American Electric Reliability Corporation ("NERC"), Morningstar, StatsCanada, National Energy Board ("NEB") of Canada, Intercontinental Exchange, Natural Gas Exchange and Enerfax, NYMEX, Cantor Fitzgerald, ClearPort, US Environmental Protection Agency ("EPA"), Nuclear Regulatory Commission, various ISOs, company annual reports, and etc.) and then organizing and auditing it. Furthermore, Ventyx, the Velocity Suite also makes adjustments and certain computations with the raw data that are then available in the Velocity Suite to subscribers, some of these computations are useful to modelers of power systems. For an overview of the Ventyx, the Velocity Suite service, please see http://www1.ventyx.com/velocity/vs-overview.asp.

[14] Among them, 759 MW were coming from "Real Time Emergency Generation". This amount of real-time generation response is in excess of the ISO-NE limit (per Tariff Section III.13.7.2.5.2.). So these resources will be paid at a lower (pro rata) price.

remuneration as compared to the opportunity costs of cutting load (the exception is emergency generation, which would not face the same opportunity costs). Overall, in the Base Case modeling, I assumed that the total volume of demand-side resources would decline slowly from the 2,900 MW, which is the total amount cleared in the second FCA. I forecast a decline of approximately 150 MW per year throughout the forecast period.

Figure 7. Map of existing generation plants in New England by size and fuel as of 2008



Source: Ventyx, the Velocity Suite

Q. What assumptions were made with respect to retirements and new capacity resources?

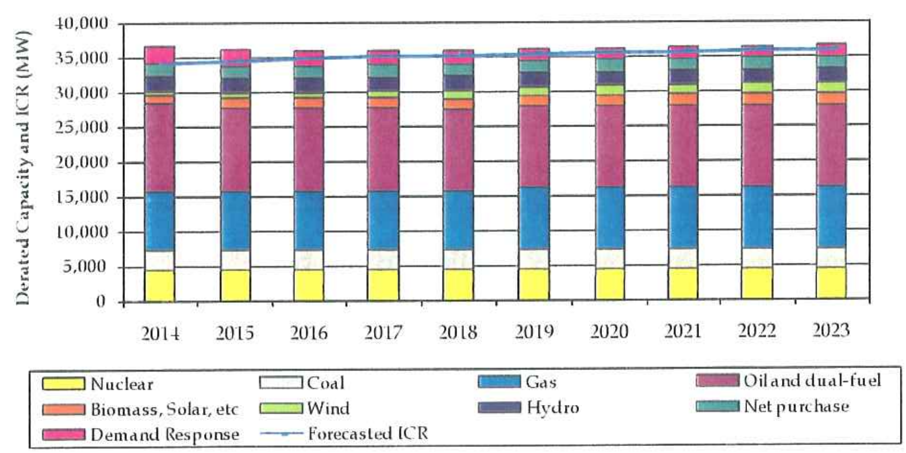
A. In addition to the existing capacity that was listed in the ISO-NE CELT report, new capacity additions and retirements were also considered in the long term forecasting exercise. New resources that cleared in the first and the second FCAs were included.[15]

[15] The identity of new resources that cleared the FCAs is disclosed by ISO-NE and was included in the Base Case with the exception of some small wind generators which are captured by the generic wind entry included to meet renewable portfolio standard targets.

In the short term, generation projects were included after a review of their relative status. For example, I reviewed whether the project has the I.3.9. approval, and/or had secured contracts[16]. I also checked whether the construction has begun or not through the review.

Under the Base Case, from 2009 through 2014, I estimated the total generating addition of about 5,000 MW. With all these short term[17] additions, the ISO-NE market is in a state of oversupply in the near term, but this excess capacity vis-à-vis demand is eventually absorbed through load growth and retirements by 2018, as summarized in Figure 8 below.

Figure 8. Cumulative system derated capacity by fuel and summer peak



Note that the capacity here is the summer capacity plus the intermittent derates applied to wind and hydro capacity

In the longer term, three criteria drive the modeled capacity additions under the Base Case: generic renewable capacity is added to the model to meet the Renewable

[16] Resources which have been awarded long-term contracts with IOUs through a bidding process held by state regulators or utilities are included because these effectively obligate plant developers with firm milestones for commercial operation.

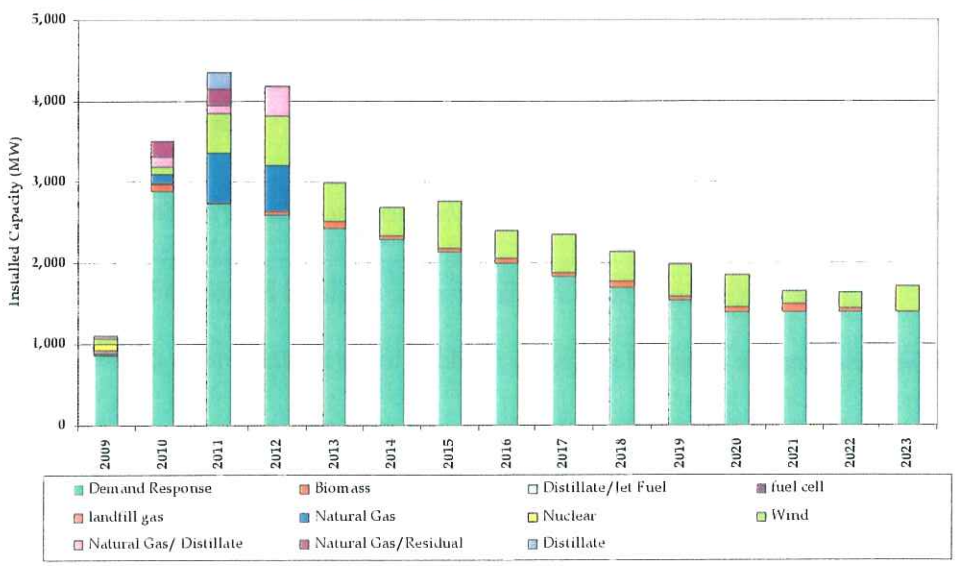
[17] I use the terms "short term", "medium term", and "long term" simply as descriptive qualifiers. There is no concrete cutoff point for short term versus medium term or medium term and long term. Generally, I would consider short term to encompass a period of a few years, with the medium term covering a five to seven year outlook, and longer term to define periods after seven years.

Portfolio Standard ("RPS") targets across the New England states. In addition, generating capacity is also added to meet the system-wide reliability requirement (i.e., such that there is sufficient capacity to meet the Installed Capacity Requirement ("ICR") in the Forward Capacity Market). In summary, I assume convergence to a balanced supply-demand condition in New England in the medium to longer term. The figures below summarize the type and quantity of new entry from 2009 through the modeling timeframe.

Figure 9. Capacity addition by fuel and by year, 2009-2023

Year In	Biomass	Distillate/ Jet Fuel	Fuel Cell	Landfill Gas	Natural Gas	Nuclear	Wind	Natural Gas/ Distillate	Natural Gas/ Residual	Distillate	Total
2009	5.6		16.2	32.0		80.0	60.0	45.8			239.6
2010	83.5	18.0			96.0		105.0	115.0	200.0		617.5
2011	3.0				620.0		485.5	99.0	200.0	207.0	1614.5
2012	55.0				555.0		620.0	365.0			1595.0
2013	75.8						462.0				537.8
2014	43.0						355.0				398.0
2015	50.0						580.0				630.0
2016	75.0						335.0				410.0
2017	50.0						470.0				520.0
2018	80.0						373.0				453.0
2019	45.0						396.0				441.0
2020	65.0						402.0				467.0
2021	105.0						153.0				258.0
2022	50.0						188.0				238.0
2023							322.0				322.0
Total	785.9	18.0	16.2	32.0	1271.0	80.0	5306.5	624.8	400.0	207.0	8741.4

Figure 10. Comparison of annual capacity additions by fuel type

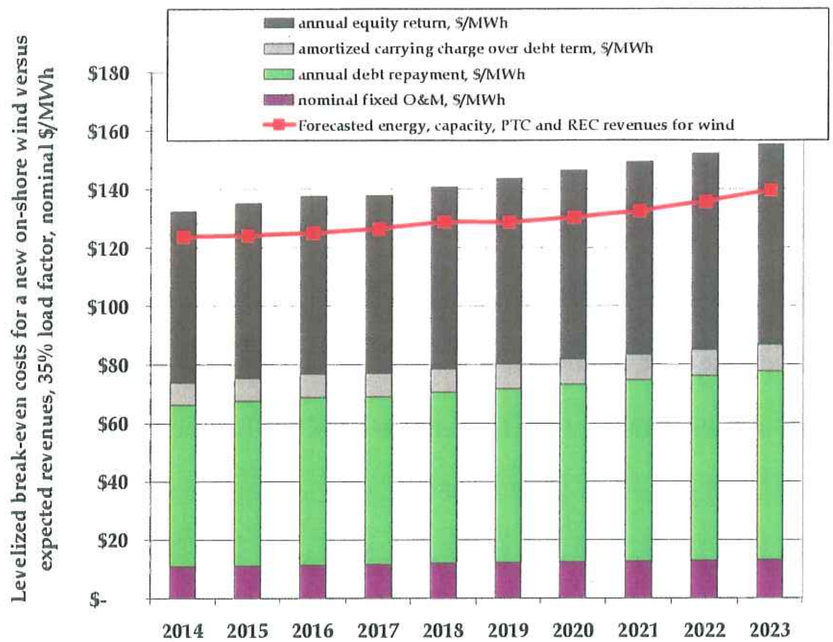


Note: All capacity in the graph above is equal to name plate capacity

Lastly, consistent with the market paradigm, a new entrant was assumed to enter into the market when expected market profits (i.e. sum of energy revenues, ancillary services payments and capacity market payments, and tax and REC incentives, where applicable) cover its all-in fixed costs (including its return on equity, debt charge, and fixed O&M). The generic capacity resources are further tested to ensure that they are indeed economic given their forecasted levelized cost of investment and operations. Given the Base Case conditions, the most suitable technologies for new entry in the New England market consists of wind generation and CCGTs. The figures below (Figure 11 and Figure 12) present the build-up of the levelized costs per year for these two technologies over the modeling timeframe. The bars in the charts represent the levelized costs, broken down by type of cost, such as debt, equity, fixed O&M and variable O&M, and fuel costs (where relevant).[18] The reader should note that the forecast "Base Case" revenues (represented by the red line) are generally in-line with the top of the bars, suggesting that forecast market profits are allowing for the recovery of the levelized all-in costs.

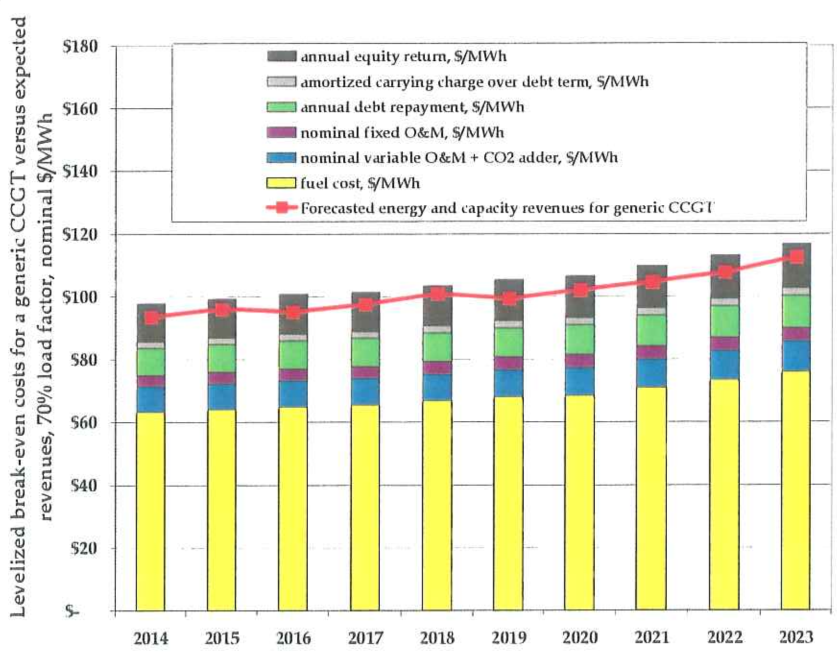
[18] The assumptions behind these costs are discussed in Appendix B.

Figure 11. Comparison of the levelized costs of generic on-shore wind projects and their projected economics



Note: For illustrative purposes, the chart assumes a PTC of $21/MWh and a REC of $20/MWh each year of the forecast time horizon.

Figure 12. Comparison of the levelized costs of generic CCGTs and their projected economics



Retirements were also reflected in the model. Given the likelihood of retirements or repowerings, three plants in Connecticut were removed from service in 2013:

Bridgeport Harbor 2 (which has a summer capacity of 130.5 MW), Norwalk Harbor 1 and 2 (which have a summer capacity of 330 MW), and Montville 5 (81 MW). These plants currently have generator reliability agreements with ISO-NE, the need for which will cease to exist once future transmission projects- such as NEEWS – are realized.[19] However, the modeling anticipated that the sites of these power plants will likely be employed for brownfield development down the road; therefore, generic new entrants in the longer term may be sited approximately in the same location as these facilities. In addition, other existing plants were retired when projected profits were insufficient to cover its going forward fixed costs; thus, simulating rational investor behavior.[20] For example, under the Base Case, an additional 867 MW of capacity was retired from 2013 through 2023, for a total of 1,409 MW of retirements over the modeling timeframe. In addition to the Base Case retirements, there are slightly higher retirements in the modeling of Meriden and the 'Additional Retirements with More Renewables' scenarios. With the inclusion of Meriden, another additional 317 MW of existing generation capacity is mothballed. Under the 'Additional Retirements with More Renewables' scenario, another additional 814 MW of generation capacities are retired above and beyond the Base Case levels described above.

Q. Were external resources considered in the modeling?

A. ISO-NE is well interconnected with surrounding regions, with ties to the New Brunswick, Quebec, and New York power markets. It would be inaccurate to ignore import resources and exports to these other markets in any modeling exercise. Therefore, the modeling did

[19] http://www.iso-ne.com/genrtion_resrcs/reports/rmr/rmr_agreements_summary_with_fixed_costs.xls

[20] The retirement analysis began with a review of projected profits. For each existing plant, combined revenues from all modeled markets are catalogued and these profits are compared to each plant's estimated minimum going forward fixed costs to derive a plant's operating profits. If a plant was estimated to earn negative operating profits for three consecutive years, it was retired. And the energy market simulations were then repeated. A three-year rule was used to reflect the observed inertia in deregulated markets across the US towards permanent plant closures, even in adverse market conditions.

consider external resources. Imports were modeled on an aggregate or composite basis using a "supply curve" approach, based on the resource mix in these external markets, actual flow patterns between markets, and adjustments for future fundamentals (such as the new entry and demand growth in these other markets relative to opportunities in New England and other interconnected markets). The transfer interfaces limits published by relevant ISOs were employed in capping the cumulative MWs associated with each external market's supply curve.[21] Notably, these thermal limits were binding only if the intertie was fully utilized. Energy from these external resources – imports – was scheduled dynamically within the model. The model made the economic choice between local resources and external resources, given defined marginal costs and transmission constraints. Exports to these external markets were represented as demand additions.

Q. How were fuel price projections developed for the Base Case?

A. Fuel prices were developed based on current market forwards over the medium term, and then transitioned to expected long run trends. More specifically, natural gas price forecasts were developed using the Henry Hub forwards from NYMEX for the short and medium term. It was then escalated at 3.5% per annum, the Dow-Jones-AIG Commodity Index natural gas historical trends.[22]

For the primary gas pricing point in New England, Boston Citygate, a historical observed differential of the Henry Hub prices and Boston Citygate prices was incorporated. Distillate oil price was based on the heating oil forwards from NYMEX and then

[21] Although there have been a number of proposed transmission projects that would expand the capacity of the cross-border interties, I have not included these projects in the current analysis. However, some of these other transmission projects may complement the economics of GSRP and therefore expand the scope for GSRP to provide market benefits.

[22] The 3.5% figure reflects the compounded annual growth rate from 1981 to 2006. This is slightly higher than pure economy-wide inflation over this period, reflecting the greater upward price pressures on gas from oil markets and demand expansion from gas-fired generation. In general, I expect similar differentials to continue into the future.

escalated based on the implied projected growth rate for crude oil from NYMEX for the near term and then the implied projected rate of growth for crude oil from US Department of Energy's Energy Information Agency (EIA) 2008 *Annual Energy Outlook* for the long term. The residual oil projections were derived from actual distillate-residual differentials. I have used plant specific coal prices given the diversity in coal sourcing, sulfur content levels, and different contracts for price and transportation. The projected plant-specific delivered coal prices were forecast using the most recent reported coal costs, with escalation annually (based on the implied inflation rate for coal from Energy Information Administration's ("EIA") 2008 *Annual Energy Outlook*). This is a standard approach and consistent with industry practice.[23] A detailed description of these assumptions can be found in Appendix B.

Q. What was the source of the demand projections?

A. The sub-region hourly load profile from 2013 to 2017 was directly taken from ISO-NE's projected zonal hourly demand projections published in the CELT.[24] [25] This is based on the ISO-NE 50/50 (or Reference Case) demand forecast. By definition, the 50/50 load forecast is an 'expected' weather forecast. Technically, the projected peak load under the 50/50 load forecast has a 50% chance of being exceeded. This is the most appropriate forecast to use in a long term modeling exercise, given the underlying logic of a long term forecast, where major assumptions and conditions – including weather – are assumed to approach or approximate the long run average value.

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[23] Furthermore, according to ISO-NE documentation, the fuel prices assumptions used in the Attachment K Economic Studies was also obtained from US EIA's 2008 Annual Energy Outlook's assumptions. See ISO-NE. PAC materials. Requests for additional clarification about Feb 25th economic study presentation.

[24] ISO-NE. CELT forecasting data details. See http://www.iso-ne.com/trans/celt/fsct_detail/index.html

[25] The ISO-NE uses the operating companies' historical load data in conjunction with the FERC 715 seasonal peaks supplied by operating companies. A discussion of the ten year forecasts for the ISO-NE sub-areas can be found at http://www.iso-ne.com/trans/celt/fsct_detail/2008/sub_area_forecast_2008_discussion.pdf

For the forecasted hourly load profile after 2017, the growth rates observed in ISO-NE's forecasts and the relative acceleration (or deceleration) in the prior two years were used to extrapolate hourly regional projections for the period 2018 through 2023.[26]

Q. Were there any volatility-based components included in the modeling?

A. Yes, POOLMod captured some of the volatility in electricity prices through the implementation of outages. Furthermore, I modeled each year thirty times with thirty different outage schedules in order to represent the variability of price to the availability of resources. The results discussed through this testimony are drawn from the distribution of market outcomes from these thirty iterations.

The use of thirty iterations allowed me to test the modeled outcomes for statistical significance and to estimate a distribution of outcomes, rather than rely on a single point-estimate. Modeling of iterations was very time intensive: 330 ten-year modeling runs were performed for the final energy market analysis. However, I can now more confidently characterize the estimated benefits of GSRP.

Q. Was the energy modeling calibrated or tested in anyway?

A. Yes, the modeling underwent a thorough calibration and testing process. Calibration runs were required to refine the new entry and retirements to model plausible and realistic economic outcomes. The modeled outcomes were also tested against historical factors and analyzed for congruency with forward market data in the near term. For example, for major existing generating plants in our resource database, I considered whether projected production schedules were comparable with historical operating profiles. In another example, the simulated patterns of flow across the system were compared with available historical data in light of differences between projected and historical fuel price and

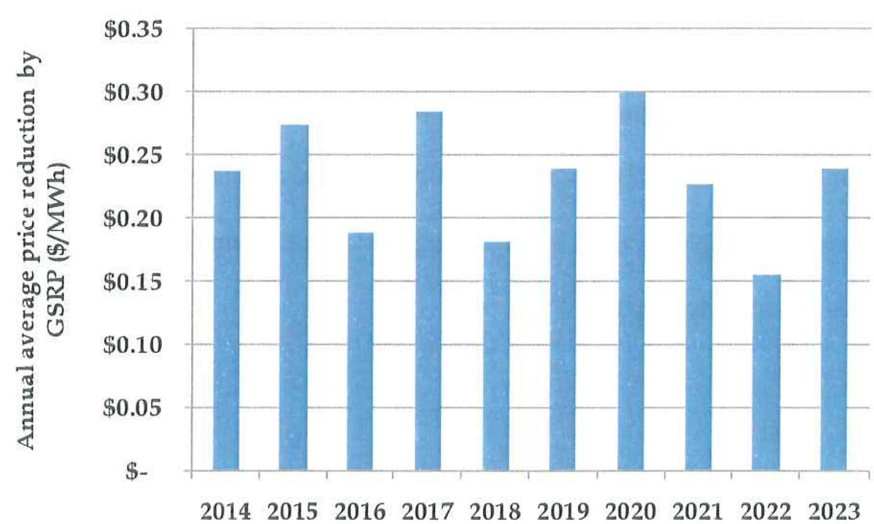
[26] For example, for 2018, I implied a load growth rate from 2017, based on annual trends between 2015 and 2017. For 2019, I looked at the 2016 through 2018 trends.

demand conditions. The model performed satisfactorily in these calibration runs and congruency checks and tests, providing me with confidence on the robustness of modeled outcomes.

Q. Please describe the energy market price reductions created by GSRP.

A. Due to more efficient dispatch and reduction in congestion (in those relatively few hours when the system is congested), GSRP creates an annual average price reduction of \$0.23/MWh on a demand-weighted basis for the ISO-NE system as a whole over the ten years. The year-by-year figures for the system as a whole are presented in Figure 13 below. Notably, these annual price reductions are actually themselves an average - each of the thirty iterations of RIRP and GSRP creates a stream of projected energy price reductions.

Figure 13. Projected annual energy price reductions resulting from GSRP, demand-weighted system-wide prices, Base Case (nominal \$/MWh)



nominal $/MWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Price Reduction	$ 0.24	$ 0.27	$ 0.19	$ 0.28	$ 0.18	$ 0.24	$ 0.30	$ 0.23	$ 0.15	$ 0.24

Note: These annual figures are based on mean of the thirty iterations.

Although the average annual price reduction seems fairly small, it is nevertheless statistically significant.[27] Furthermore, this modest price reduction creates substantial cost savings to consumers. For example as shown in Figure 14, according to 2008 ISO-NE CELT Report, New England system-wide energy consumption in 2014 is projected to be 146,467 GWh. This level of consumption, coupled with the projected energy price reductions, yields $35 million in cost savings for the New England market in 2014.

Figure 14. An example of cost savings from GSRP for New England in 2014, Base Case

Price Reduction × Consumption = Energy Market Savings

2014 Calculation Example for GSRP

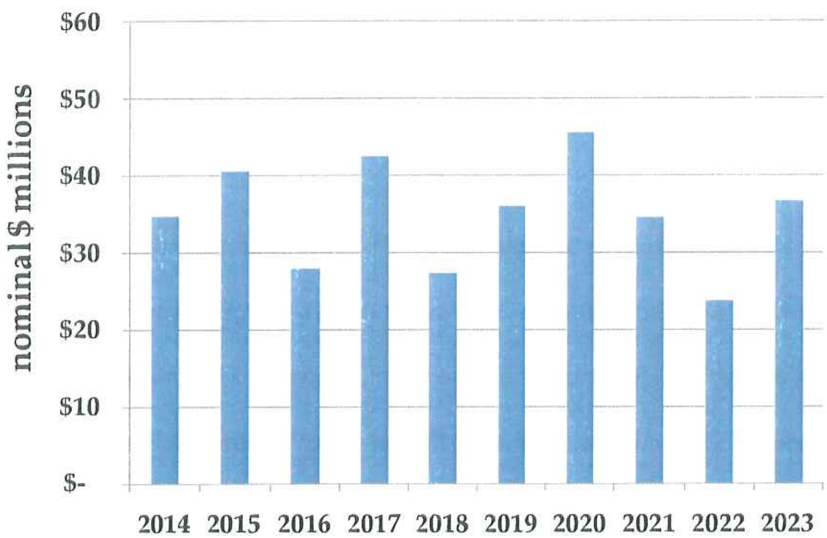
$0.24/ MWh × 146,467 GWh × 1,000
= $ 35 million

Q. What is the expected energy market benefit for GSRP under the Base Case?

A. Based on the above calculations and the averages from the thirty iterations, I present below the projected annual energy benefits for GSRP. These annual figures range from $24 million to over $45 million per year. As seen, the annual energy benefit closely follows the change in annual average energy price reductions, which are sensitive to annual capacity new entry.

[27] Statistical tests of these price reductions confirm that these results are statistically significant and robust at the 95% level of confidence. In other words, the statistical tests conclude that the price reductions observed are genuinely related to GSRP rather than the potential stochastic price effect of plant maintenance and availability schedules.

Figure 15. Annual energy benefit of GSRP in Base Case, 2014-2023 (nominal $ millions)



(nominal $ millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
GSRP Energy Benefit	$ 34.8	$ 40.5	$ 28.0	$ 42.5	$ 27.4	$ 36.1	$ 45.6	$ 34.6	$ 23.8	$ 36.7

Note: These annual figures are based on mean of the thirty iterations.

Q. What is the range of energy market benefits for GSRP under the Base Case?

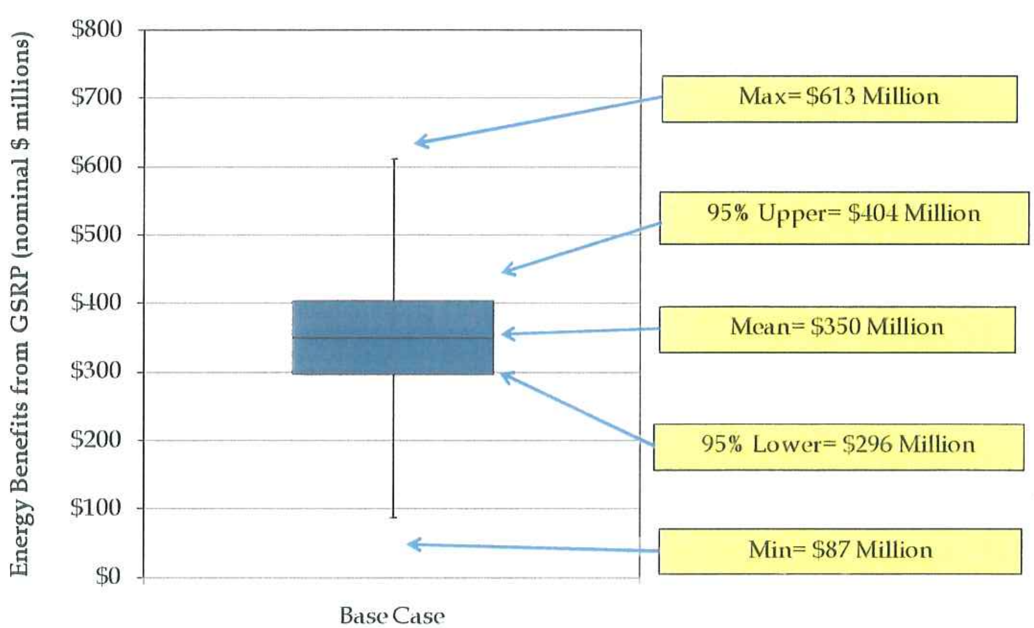
A. A range of energy market benefits for GSRP under the Base Case can be estimated from the thirty iterations of price projections. The thirty iterations produce a sufficiently large sample such that I can construct a distribution of potential benefits.[28] Using this distribution, I then estimated the upper and lower boundaries for expected energy market benefits under different confidence levels. Figure 16 shows that the 95% confidence interval for the ten-year cumulative sum of the energy benefits of GSRP under the Base Case is between $296 million and $404 million (the 50% value or mean is equal to $350 million, which is the sum of the individual values presented in Figure 15 above). In addition, the figure below shows that from the thirty-iteration distribution, the minimum

[28] By applying the Law of Large Numbers (LLN), I estimate the distribution and construct the confidence intervals of potential benefits. LLN shows that as the number of random samples increases, the estimated sample average converges to its population mean and the distribution converges to a normal distribution.

ten-year cumulative sum of energy market benefits observed was $87 million – GSRP always produced some level of energy market benefits in the modeling. In addition, in one of the thirty iterations under the relatively conservative Base Case, the economic benefits from the energy market reached a cumulative sum of $613 million over ten-years. [29]

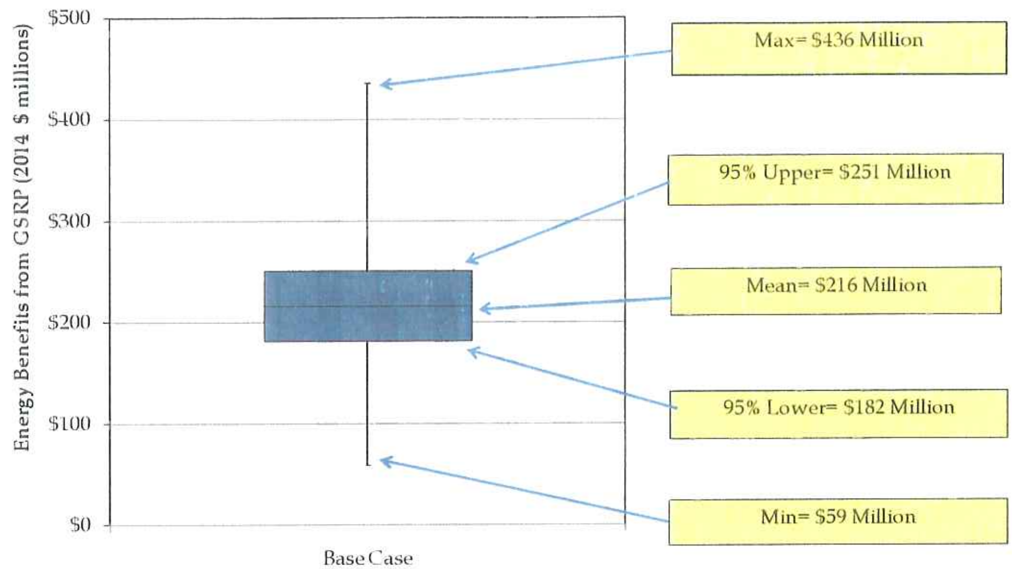
I also calculated the present value ("PV") of the annual energy benefits using a 10% discount rate (discounting to 2014 dollar terms). The 95% confidence interval for the PV of energy benefits under the Base Case is between $182 million and $251 million with a mean of $216 million. Similarly, the ten-year PV sum is $59 million for the observed minimum case in the thirty iterations and $436 million for the observed maximum case in the thirty iterations on a PV basis.

Figure 16. Ten-year cumulative sum of energy benefits of GSRP under the Base Case (nominal $ millions)



[29] These observed minimum and maximum observations have a probability less than 1% under the normal distribution.

Figure 17. Present Value sum of energy benefits of GSRP under the Base Case (2014 $ millions)

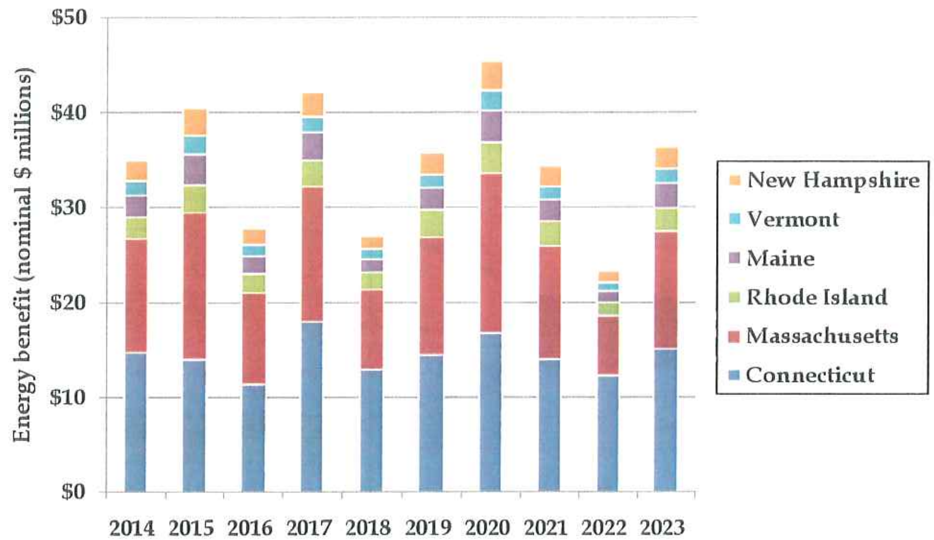


Note: Discount rate of 10% applied to discount future values to 2014 dollar terms.

Q. What portion of the projected energy market benefits accrue to Connecticut ratepayers?

A. The figure below provides a summary of the state-by-state breakdown of energy market benefits from the Base Case. Notably, all consumers in New England benefit from GSRP, although the magnitudes of the energy market benefits are smaller for those states where either the price reductions or consumption levels are smaller (relative to other states).

Figure 18. Breakdown of annual projected energy benefits by state in the Base Case (nominal $ millions)

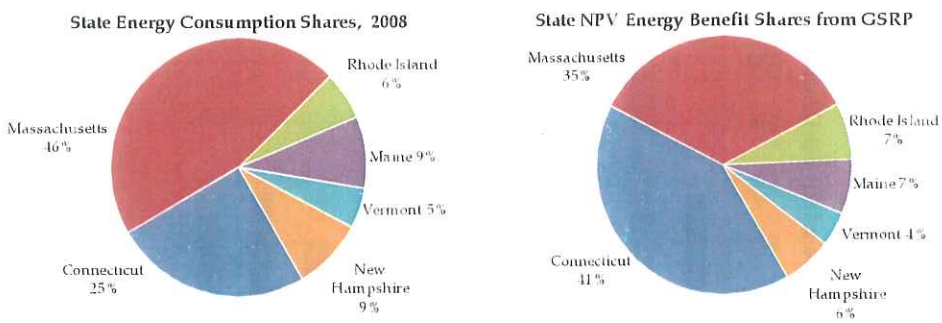


Note: These annual figures are based on mean of the thirty iterations.

Energy market benefits are a function of prices and energy consumption levels. Connecticut has historically accounted for approximately 25% of energy consumption in ISO-NE and it is expected to remain at about this level for the next ten years per 2008 ISO-NE CELT report[30]. However, Connecticut is estimated to receive over 40% of the system-wide energy benefits under the Base Case, because Connecticut's LMP reductions are slightly more than those in other sub-regions of New England. Massachusetts consumes the most electricity of all the states - about 46% of total energy consumption within New England, and will enjoy about 35% of the system-wide energy benefits due to GSRP. For other states, generally, the share of energy benefits is close to their share of system-wide electricity consumption. Figure 19 provides a comparison of the consumption shares and the PV of energy benefits to illustrate the similarities.

[30] In the 2008 ISO-NE CELT forecast, the share of total load ranges from 25% to 26%, while the peak load share range from 26% to 27%.

Figure 19. State energy consumption and benefit shares from GSRP in Base Case



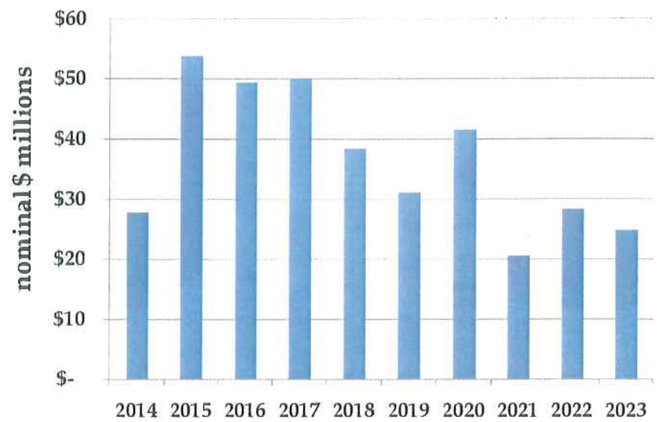
Source: Energy consumption data is from 2008 ISO-NE CELT

Q. What would happen to the energy market benefits from GSRP if fuel prices are higher than the assumptions in the Base Case?

A. The 'High Fuel Prices' scenario was created in order to analyze this question. The gas and oil prices from the Base Case were escalated by 72%. More specifically, the underlying crude oil price projection was increased from approximately $90/barrel of oil to $155/barrel of oil, based on the actual observed price points experienced in 2008. The increase in oil prices results in energy benefits for GSRP equal to $366 million on a ten-year cumulative sum basis or $235 million on a PV basis (both numbers represent system-wide benefits to New England as a whole and the average observed from the thirty iterations). The $235 million figure is about $19 million greater than the comparable $216 million PV under the Base Case.

An increase in gas and oil prices raise the economic value of GSRP because the increase in fuel prices translates into an increase in the energy prices, which magnifies the energy price reduction that could be achieved by GSRP and hence increases the energy market benefits from the project.

Figure 20. Annual energy benefit of GSRP in the 'High Fuel Prices' scenario, 2014-2023 (nominal $ millions)



(nominal $ millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
GSRP Energy Benefit	$ 27.8	$ 53.8	$ 49.5	$ 50.1	$ 38.5	$ 31.1	$ 41.5	$ 20.6	$ 28.3	$ 24.7

Note: These annual figures are based on mean of the thirty iterations.

The 95% confidence interval around the $235 million PV for the 'High Fuel Prices' scenario ranges from $188 million to $282 million, as seen in Figure 21. Similarly, Figure 22 shows the 95% confidence interval around the ten-year cumulative sum for the 'High Fuel Prices' scenario ranges from $291 million to $441 million.

Figure 21. Present Value sum for system-wide energy market benefits under the Base Case and 'High Fuel Prices' Scenario, 95% confidence interval and average (2014 $ millions)

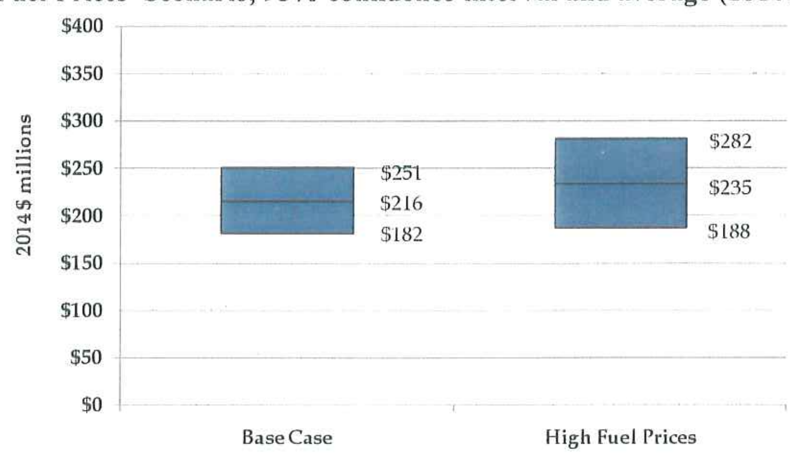
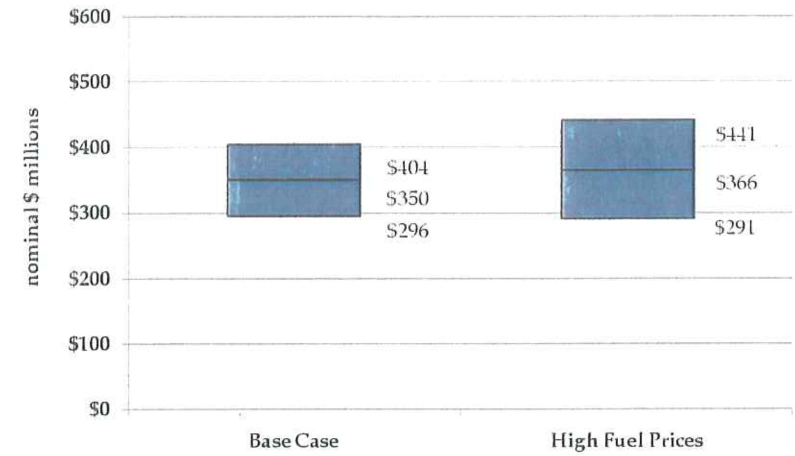


Figure 22. Ten-year cumulative sum of system-wide energy market benefits under the Base Case and 'High Fuel Prices' Scenario, 95% confidence interval and average (in nominal $ terms)



Q. Are GSRP's estimated economic benefits from the energy market affected by retirements?

A. Yes, the energy benefits of GSRP are contingent on the state of retirements (and capacity replacements). I modeled a scenario where I assumed additional retirements in Connecticut of older, fossil-fuel fired units.[31] In order to re-balance the system for these retirements, I then introduced more generic renewables generation in northern New England.[32] I labeled this case the 'Additional Retirements with More Renewables' scenario. The resulting energy market benefits for New England as a whole average $45 million per year for a cumulative sum of $446 million over ten years. This scenario forecasts energy market benefits that are about $10 million per year higher than that in the Base Case, as shown in Figure 23.

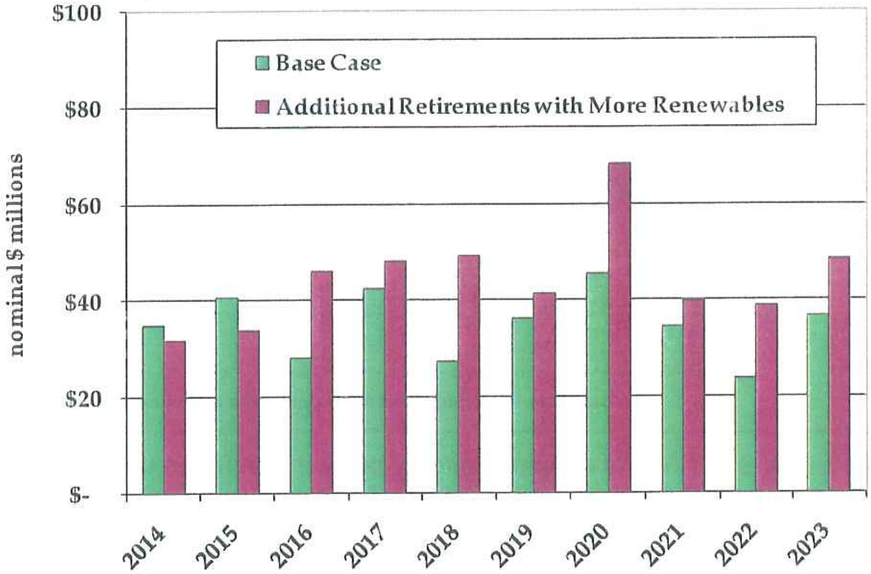
[31] The units are Montville 6 and Middletown 4 with a total capacity of 807 MW.

[32] The replacement renewables in this scenario include 1,463 MW of hydro generation in New Hampshire zone and 714 MW of wind generation in Western Massachusetts and Vermont zone. As seen, the replacement amount is more than the retirements because the renewables are intermittent resources and cannot guarantee resource adequacy as thermal generation capacities do. The renewables replacements have a generation capacity equivalent to 800 MW of thermal generation retirements.

On a PV basis under the 'Additional Retirements with more renewables' scenario, GSRP creates an expected energy market benefit of $267 million over the modeled ten years, which is approximately $51 million higher than in the Base Case. This scenario is forecast to have a 95% upper bound of $308 million and lower bound of $226 million (in PV terms and at a 10% discount rate). At the upper bound of the 95% confidence interval, GSRP's energy market benefits (alone) can cover over 40% of the estimated investment costs in 2014 dollar terms. Notably, the 95% confidence interval is higher than that observed in the Base Case (Figure 24). GSRP will create larger regional market benefits if in fact older plants are retired in Connecticut with more renewables energy is employed to meet load in New England.

Similarly, Figure 25 shows the 95% confidence interval around the ten-year cumulative sum for the 'Additional Retirements with More Renewables' scenario, which ranges from $373 million to $518 million.

Figure 23. Project annual energy benefits of GSRP in 'Additional Retirements with More Renewables' scenario, 2014-2023 (nominal $ millions)



nominal $ millions	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Base Case	$ 34.8	$ 40.5	$ 28.0	$ 42.5	$ 27.4	$ 36.1	$ 45.6	$ 34.6	$ 23.8	$ 36.7
Additional Retirements with More Renewables	$ 31.7	$ 33.9	$ 46.0	$ 48.2	$ 49.2	$ 41.3	$ 68.1	$ 39.9	$ 38.8	$ 48.4

Note: These annual figures are based on mean of the thirty iterations.

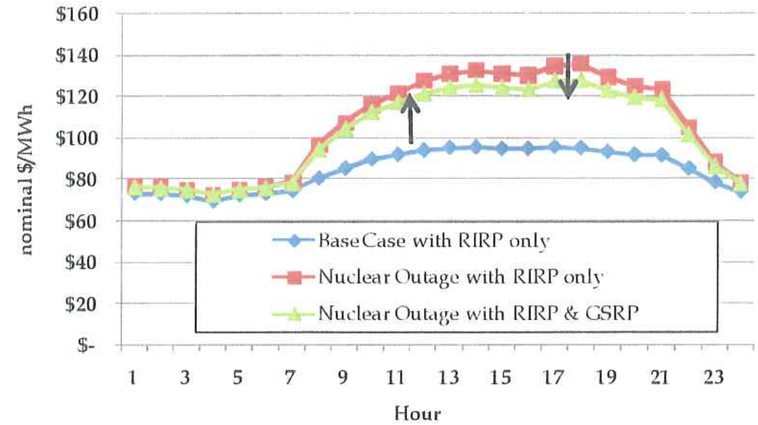
Figure 24. Present Value sum of energy market benefits under the Base Case and the 'Additional Retirements with More Renewables' Scenario, 95% confidence interval and average (2014 $ millions)

Figure 25. Ten-year cumulative sum of energy market benefits under the Base Case and the 'Additional Retirements with More Renewables' Scenario, 95% confidence interval and average (nominal $ terms)

Q. What happens to GSRP's estimated energy market benefits in the case of an unexpected nuclear outage?

A. I tested the implications of an unexpected, year-long nuclear plant outage with and without GSRP for three sample years within the forecast timeframe. Under the situation of an outage of the Millstone nuclear units, the New England system would experience much higher prices and higher levels of congestion. The presence of GSRP offsets some of the increases in LMPs, as seen in the figure below, which shows the change in Connecticut average hourly LMPs for 2014. During an event of nuclear power outage, the hourly price increases by 25% or $21/MWh on average compared with the Base Case. GSRP can offset up to $4/MWh of the projected energy costs increase due to such an outage. In other words, it provides "insurance" or a "hedge" against some of the costs of such high impact events.

Figure 26. Energy price comparison between Base Case and 'Nuclear Outage' scenario, average hourly LMPs for Connecticut zone in 2014 (nominal $/MWh)



Note: These hourly figures are annual average of hourly prices over thirty iterations.

On a system-wide basis, the projected energy market benefits associated with GSRP under a nuclear outage total <u>more than</u> $250 million (in nominal terms) for one year (or close to $400 million on average given 2018's supply-demand conditions). This annual projected energy benefit is seven times the average annual projection in the Base Case.

Figure 27. Annual energy benefit of GSRP in 'Nuclear Outage' scenario, selected years (nominal $ millions)

	2014		2018		2022	
nominal $ millions	Nuclear	Base Case	Nuclear	Base Case	Nuclear	Base Case
GSRP energy benefits	$ 265.0	$ 34.8	$ 390.6	$ 27.4	$ 340.0	$ 23.8

Note: These annual figures are based on mean of the thirty iterations.

Figure 28. Comparison of annual energy market benefits under the Base Case and Nuclear Outage Scenario, 95% confidence interval and average, (selected years, nominal $ millions)

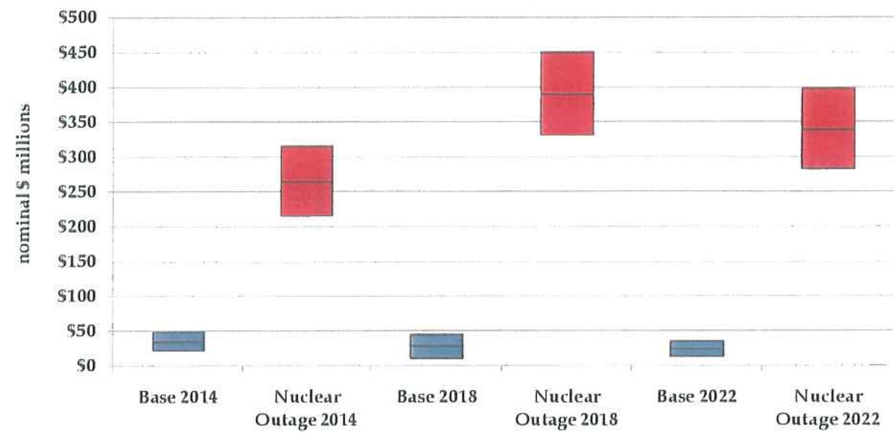


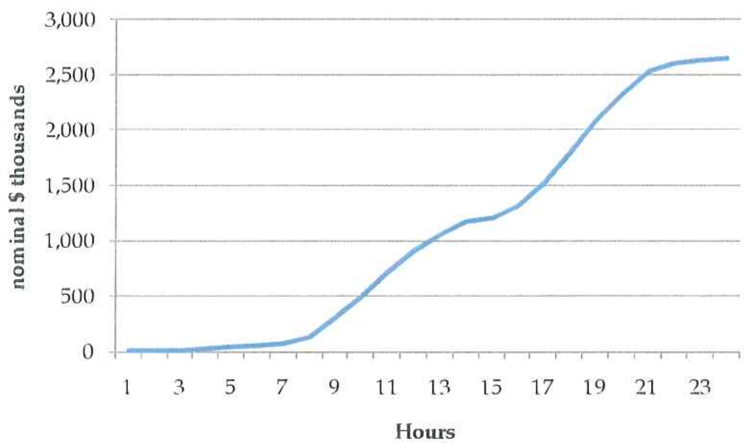
Figure 28 above illustrates how the range of annual distributions of energy market benefits differs between the Base Case and the 'Nuclear Outage' scenario. Note that the red bars (representing the nuclear outage scenario) are much thicker than the blue bars. The insurance value of GSRP is embedded in these modeled outcomes. Specifically, the distribution of benefits from GSRP ranges from $215 million to $450 million in the three years reviewed (assuming a 95% confidence level).

Q. Are there other indications of GSRP's insurance value with respect to the energy market?

A. Yes, a 'High Demand' scenario was created to analyze how GSRP would affect market outcomes during an 'above average' hot summer week. This scenario moves away from the 50/50 weather normalized demand used in the Base Case and incorporated the ISO-NE's 90/10 demand forecast, which specifies peak demand levels that have only a 10% chance of being exceeded (in contrast to the 50% likelihood for the 50/50 case).

During an 'above average' load week, which is approximated by scaling to ISO-NE's 90/10 demand forecast, there are substantial bottlenecks on the CT Import interface. Under such conditions, the insurance value that GSRP provides against high market costs is obvious. The figure below shows how these energy market cost savings accrue per hour over the week for the Connecticut load zone. As seen in Figure 29, GSRP has the potential to create over $2.5 million in cost savings for Connecticut ratepayers during a moderately high load week. In particular, the cost savings build up during peak hours, exactly when the opportunity costs of transmission congestion is highest. Under some hours, without GSRP, Connecticut may be experiencing supply shortfalls and system-wide outages. GSRP alleviates those possibilities.

Figure 29. Cumulative energy market cost savings over one week for the state of Connecticut under moderately high demand conditions (nominal $ thousands)



Q. Please describe the modeling you performed of the LFRM?

A. The modeling of LFRM adheres to the pertinent market rules and ISO-NE practices. A three stage approach was implemented to model the LFRM market. First the potential qualified LFRM capacity in a particular period was identified, and then a clearing price was determined by modeling the opportunity costs of providing this ancillary service. These opportunity costs were based on ISO-NE locational forward reserves requirements ("LFRR") procurement target forecasts by zone and an estimated fixed adjustment factor designed to consider the frequency of reserve activation. Lastly, the LFRM prices were allocated to resources whereby the cleared MWs for each qualifying resource was based on the merit order derived from net fixed costs.

I started the analysis with the ISO-NE's latest predictions of LFRRs available in fall of 2008 (from the 2008 RSP). These were used in modeling the LFRM under the Base Case (without GSRP). It is notable that ISO-NE's forecasts in RSP 2008 take into account the SWCT Reliability Project Phase II and NSTAR 345 kV Transmission Reliability Project as discussed above. However, ISO-NE did not publish LFRR predictions for GSRP because it is outside the forecast timeframe. As a result, I estimated likely adjustments ISO-NE would apply to the LFRRs as a result of GSRP based on the way ISO-NE has historically adjusted or forecasted LFRRs. The fundamental issue, based on observed experience with other transmission projects, related to how much of the additional transmission capacity is going to be available for reserves (and will not be utilized for energy). The residual capacity is determined by comparing how much additional energy is flowing across the CT Import interface based on the simulations with the 200 MW of transmission capacity added to the interface (under GSRP). More detailed discussion of the analysis can be found in Appendix A.

Next, the clearing price was determined by modeling the opportunity costs of providing this ancillary service from the system's perspective. The cost of reserve service is a function of foregone opportunity costs from energy sales and activation costs; therefore, POOLMod was employed to estimate the system-wide opportunity costs of reserve service given the underlying supply and demand conditions. These opportunity costs were then converted into the 'market-clearing' payment per unit of capacity (the "Forward Reserve Credit") that suppliers would demand in order to commit to provide forward reserves, equivalent to the auction clearing price in the Locational Forward Reserve Auctions less the FCM price.

Lastly, not all capacity in the market gets paid LFRM revenues given the technical and economic constraints. The technical constraints are determined by the plant's ramp rate and prime mover type while the economic constraint is determined by the plant's heat rate vis-à-vis the strike price. A plant's LFRM capacity is determined by meeting both constraints. The LFRM qualifying capacity is then converted to a supply stack based on the merit order derived from fixed costs less expected profits from energy market sales. The cumulative sum of all qualified capacity below the projected LFRR for a particular zone is then assumed to clear the auction and is then paid the Forward Reserve Credits.

Q. How will GSRP affect the LFRM?

A. By introducing GSRP, LFRRs for the Connecticut zone are projected to decline. The reduction in the LFRR will also result in a decrease in the LFRM auction clearing prices (and Forward Reserve Credits), because the average system cost of providing reserve will decrease with smaller procurement volumes. In summary, the costs of LFRM procurements should decrease as a result of GSRP.

Q. What were your modeling results of GSRP with respect to the LFRM for the Base Case?

A. In order to understand the modeling results, I need to begin with the LFRR forecast. Figure 30 shows the projected annual LFRRs for CT under the Base Case with just RIRP and the Base Case with GSRP. After GSRP is added, the LFRRs projected for Connecticut decline. The decline is achieved because under typical on-peak conditions, the additional transmission capacity created by GSRP on the CT Import interface is not used for energy flows, and therefore is available as reserve support.

Figure 30. Projected annual LFRRs changes for CT after introducing GSRP under the Base Case (MW)

Base Case	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	505	505	506	506	506	506	506	505	506	506
Change in LFRRs	-195	-195	-194	-194	-194	-194	-194	-195	-194	-194

Note: Annual LFRR are calculated individually for each of the thirty iterations, and then averaged to illustrate the change for presentation purposes.

The unit costs of reserves also declines as a result of GSRP. As seen in Figure 31, the LFRM clearing prices are about $0.2/kW-month lower on an annual average basis for the Connecticut zones.

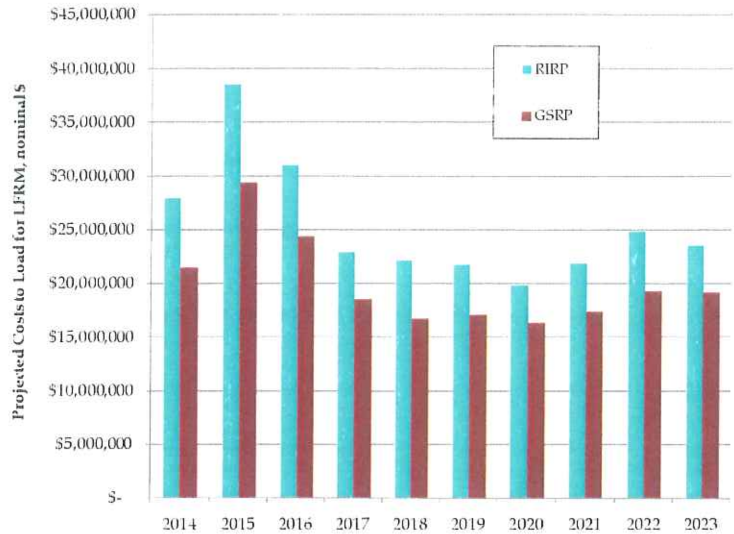
Figure 31. Projected annual change in auction prices for LFRM net of FCM prices as a result of GSRP (nominal $/kW-month)

RIRP vs. GSRP	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
CT State	$0.22	$0.30	$0.22	$0.14	$0.21	$0.19	$0.13	$0.18	$0.20	$0.16

Q. What is the impact on consumers' costs from LFRM in the Base Case?

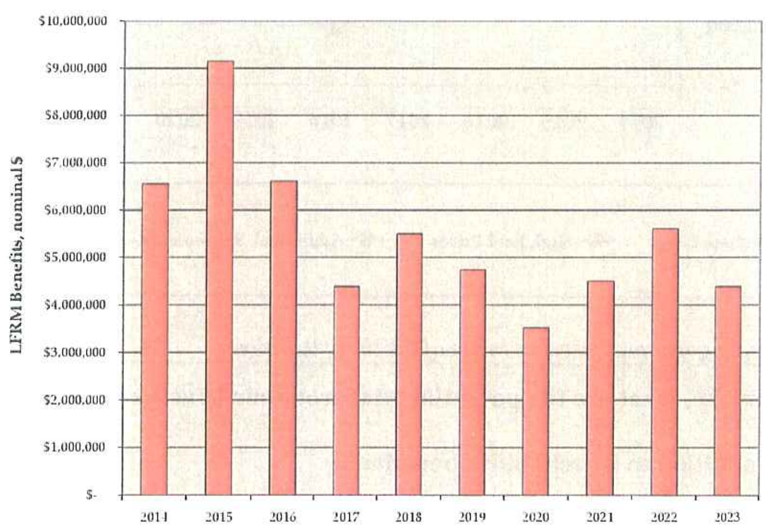
A. Figure 32 presents the LFRM cost to load calculations for the Base Case for the ISO system as a whole under the Base Case with RIRP and then with GSRP. As briefly discussed above, the costs to load for LFRM decrease as a result of GSRP, creating LFRM benefits. The annual LFRM benefits (based on the average of the thirty iterations) are presented in Figure 33 below. For the ISO-NE system as a whole, GSRP creates LFRM benefits totaling over $54 million over the ten year time horizon under the Base Case (in nominal dollar terms), or nearly $36 million on a PV basis (in 2014 dollar terms) using a 10% discount rate. Note that these values are the mean of the thirty iterations. Therefore, LFRM benefits could be even higher.

Figure 32. Projected system-wide LFRM cost to load under the Base Case (nominal $)



Note: These annual figures are based on mean of the thirty iterations.

Figure 33. Projected system-wide LFRM benefits under the Base Case (nominal $)

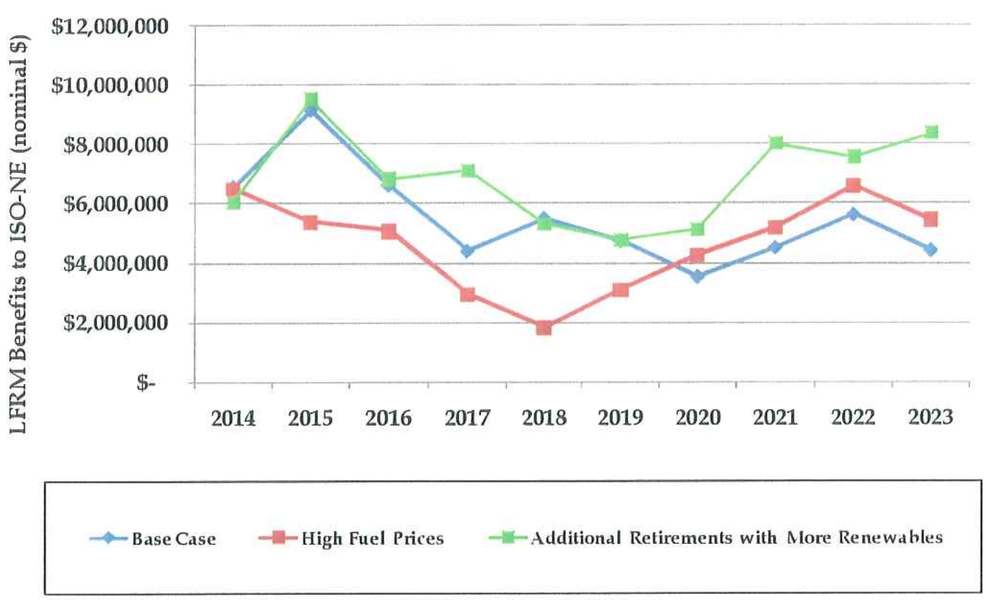


Note: These annual figures are based on mean of the thirty iterations.

Q. How do LFRM benefits associated with GSRP change with respect to higher fuel prices or more retirements and additional new entry?

A. With higher fuel prices, LFRM benefits are reduced because of both smaller incremental changes in LFRM prices and the LFRRs reduction due to GSRP. However, the reduction in LFRRs is the major force for the change in LFRM benefits. However, under the scenario with 'Additional Retirements with more renewables', LFRM benefits due to GSRP rise to almost $69 million over the ten –year forecast time horizon (nominal terms). As seen in Figure 34, the LFRM benefits for New England as a whole are more than $4 million per annum in all scenarios on an annual average. The figure below provides a year-on-year comparison of LFRM benefits for the Base Case, the 'High Fuel Prices' scenario and the 'Additional Retirements with More Renewables' scenario.

Figure 34. Projected system-wide LFRM benefits across all scenarios (nominal $ terms)

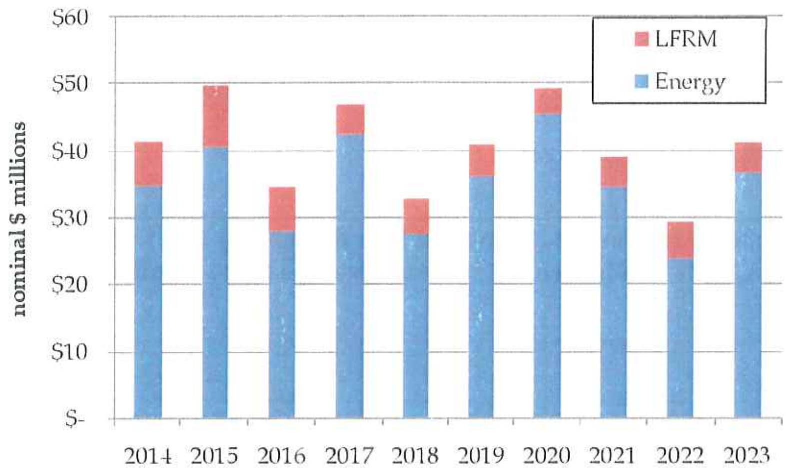


Note: These annual figures are based on mean of the thirty iterations.

Q. In summary, what are the potential total economic benefits of GSRP, apart from and in addition to its reliability benefits?

A. A total market benefit figure for GSRP can be derived by adding the energy market and LFRM benefits. Figure 35 shows the annual system-wide energy and LFRM benefits with GSRP under the Base Case – this is the average or mean value from the thirty iterations. The annual energy and LFRM benefits range from nearly $30 million to nearly $50 million per year in nominal dollar terms. The ten-year cumulative sum is equal to approximately $405 million in nominal dollar terms.

Figure 35. Projected annual average system-wide energy and LFRM benefits with GSRP in Base Case (nominal $ millions)



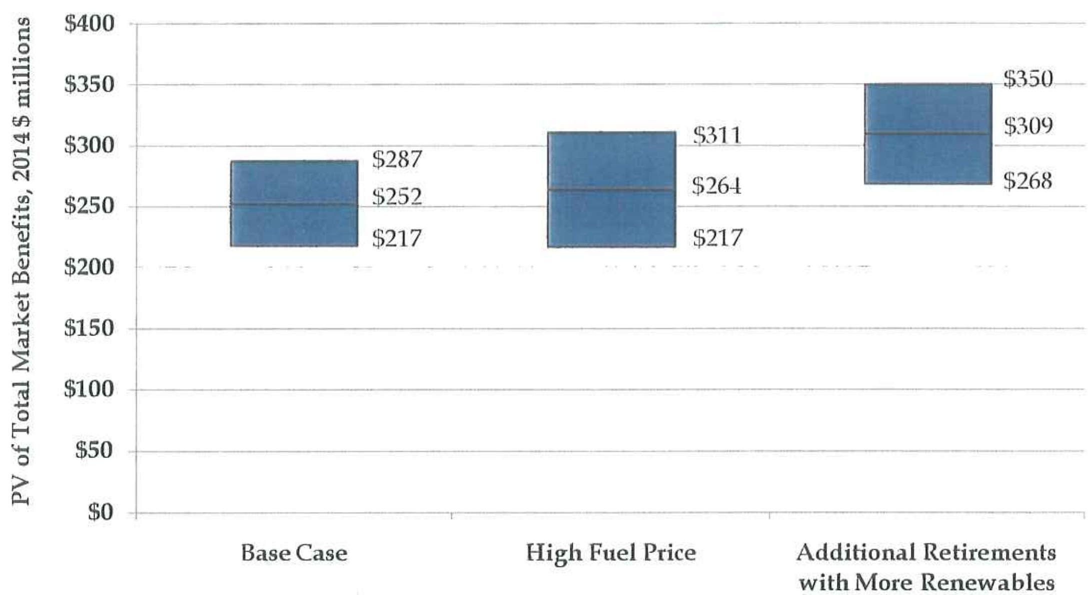
Note: These annual figures are based on mean of the thirty iterations.

Figure 36 shows the 95% confidence interval of the PV of total market benefits (energy and LFRM benefits) created by GSRP under the Base Case, the 'High Fuel Prices' scenario and the 'Additional Retirements with more renewables' scenario. Due to the discounting (10%), these PV are smaller than the cumulative sum discussed above. However, the PV is the more appropriate parameter to compare against GSRP's $714 million investment cost.

- Under the Base Case, the 95% confidence interval for the PV of total benefits ranges from $217 to $287 million, with an average of $252 million.
- Under the 'High Fuel Prices' scenario, the 95% confidence interval for the PV of total benefits ranges from $217 to $311 million, with an average of $264 million.
- Under the 'High Fuel Prices' scenario, the 95% confidence interval for the PV of total benefits ranges from $268 to $350 million, with an average of $309 million.

Looking at the upper bound of the 95% confidence interval, the relatively conservative Base Case forecast of total market benefits for GSRP would cover as much as 42% of the investment costs of GSRP, while under the 'Additional Retirements with More Renewables' scenario, estimated total market benefits can cover nearly 50% of the $714 million investment costs.

Figure 36. Present value sum of total market benefits (energy and LFRM) of GSRP under various scenarios, 95% confidence interval and average (2014 $ millions)



3 Economic Analysis of the Meriden project

Q. Please describe the analysis you performed of the Meriden project.

A. Although no determination has been made that Meriden could meet the reliability need that GSRP has been proposed to resolve, I was asked to evaluate the likely economic benefits of Meriden to Connecticut ratepayers, assuming that GSRP is not built, and that Meriden is built pursuant to a contract for differences ("CFDs"), such as which NRG Energy Inc. proposes in its application.

I took the Base Case with RIRP and added the Meriden project into the supply mix in 2014 and named this the "Meriden" case.[33] I then recalibrated the "Meriden" case to represent the dynamic generation response that would occur over time.[34] The Meriden plant re-introduces over-supply into the system, displacing some existing generation but also affecting future investors' decision to enter (for example, additional generation may not be able to secure a capacity supply obligation there is now oversupply vis-à-vis the ICR). In summary, I re-calibrated the Meriden case such that it converges to a balanced supply-demand state in the longer term.

The benefits of Meriden would be measured by the differences created in market prices for energy, LFRM, and FCM between the Base Case (RIRP only) and the Meriden case. The energy and FCM profits paid to Meriden would also impact the CFDs payments.

Q. What assumptions did you make in this modeling with respect to the Meriden project?

A. Meriden was modeled consistent with the plant parameters described in NRG's

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[33] For convenience and ease of comparison of the modeling results, I analyzed the same modeling timeframe as considered for GSRP and therefore considered 2014 as the notional "start date" for purposes of my analysis.

[34] Like the modeling for GSRP, the Meriden Case was also completed on the basis of thirty iterations.

application with the CSC and/or the information it provided in response to the CEAB RFP.[35,36] Meriden was modeled as a CCGT with an installed capacity of 540 MW (summer capacity of 510 MW and winter capacity of 530 MW), with the heat rate of 7,000 MMBtu/MWh. I assumed a maintenance schedule of 3 weeks per year and a forced outage rate of 6.7%, consistent with NRG's application and general information for the type of technology being proposed.

Q. What would be the costs of the Meriden project?

A. I estimated the levelized contract costs for Meriden based on the information provided in the application on investment costs ($1,400 per kW), leverage (50%), debt rate (8.5%), in combination with other assumptions necessary for such an analysis (e.g., 36 month long construction period for amortized carrying charges, 40% tax rate, 16% after-tax required return on equity, and a ten year debt term and equity recovery term to match the contract term). The levelized cost also included a fixed O&M estimate of $23/kW-year escalating at 2%, consistent with our generic new CCGT assumptions). The levelized all-in fixed costs per annum were estimated to be $21.3/kW-month in 2014 (about $138 million per year) and rising to $21.7/kW-month (about $141 million per year) by the end of the forecast time horizon. These levelized costs are generally consistent with the figures estimated and presented in the Meriden application.[37]

I then constructed a financial model that would take the levelized all-in fixed costs and consider the offsets that would apply given a CFDs structure. I estimated offsets for energy profits earned and also capacity market revenues.[38] The resulting

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35 http://www.ctenergy.org/NEEWSRFP.html

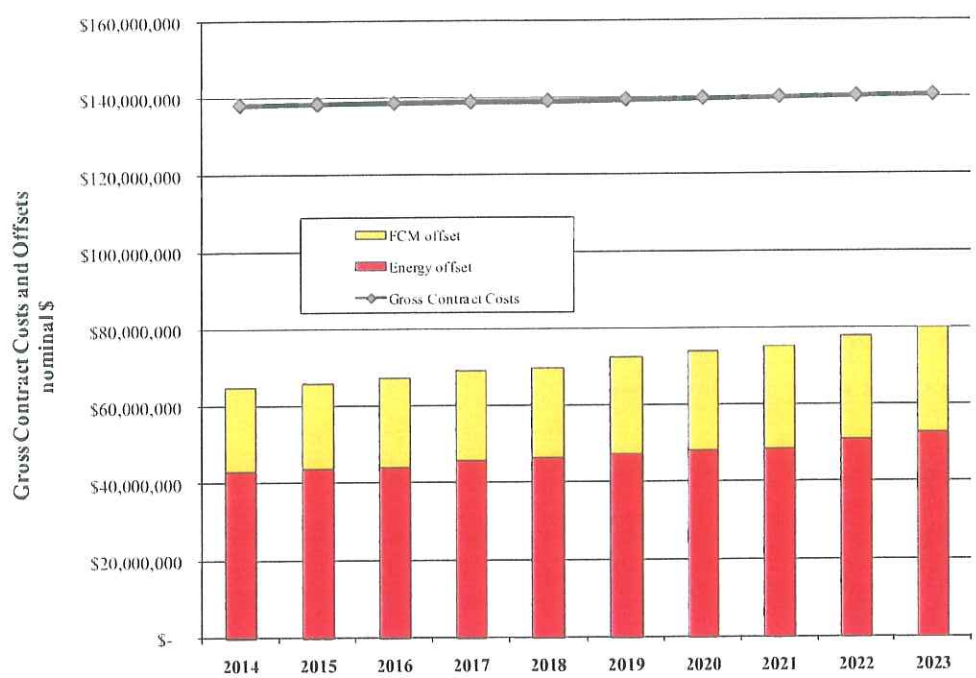
36 http://www.ct.gov/csc/cwp/view.asp?a=962&Q=437462&PM=1

37 I have used a higher cost of capital, in order to preserve a reasonable differential in weighted average cost of capital of a regulated transmission versus contracted (but unregulated) generation project.

38 These were specifically extracted from the Meriden case results, based on the average of the thirty iterations. Since the peak energy rent ("PER") is going to be refunded back to ratepayers, the FCA payment is reduced by 12-

annual net contract cost totaled $60 to over $70 million, as illustrated in the figure below by comparing the distance between the black line and the top of the bar for each year.

Figure 37. Estimating Meriden's contract costs



Note: The annual figures for energy offset and FCM offset are taken from the market simulations, which were done on the basis of thirty iterations. These numbers represent the mean of the thirty iterations.

Q. What levels of energy price reductions did you estimate as a result of the Meriden project under the Base Case?

A. In the initial five years of the forecast time horizon, Meriden produced energy price reductions (on a demand-weighted basis) of about $2.5 per MWh in Connecticut (as seen in the figure below)[39]. However, a downward trend is visible in the magnitude of the LMP reduction, even after the first few years, as Meriden's impact on other generators'

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month rolling average PER adjustment. The PER is calculated based on demand-weighted zonal PERs for Connecticut, based on forecasts of Connecticut LMPs under the Meriden Case.

[39] The projected LMP reductions for Connecticut are robust, given the test for statistical significance.

entry or exit decision is realized: in 2017, another existing CCGT exits the market (based on the economic retirement rules). The Base Case had a small generic new CCGT unit also entering the market in 2019. However, Meriden affectively forestalls that new generation investment. Therefore, the LMPs in the Meriden case and the Base Case (with RIRP only) start to converge in the longer term

Figure 38. Annual average energy price reduction in Connecticut as a result of Meriden, 2014-2023 (nominal $/MWh)

nominal $/MWh	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Price Reduction	$ 2.53	$ 2.49	$ 2.55	$ 2.34	$ 2.32	$ 0.73	$ 0.58	$ 0.53	$ 0.52	$ 0.57

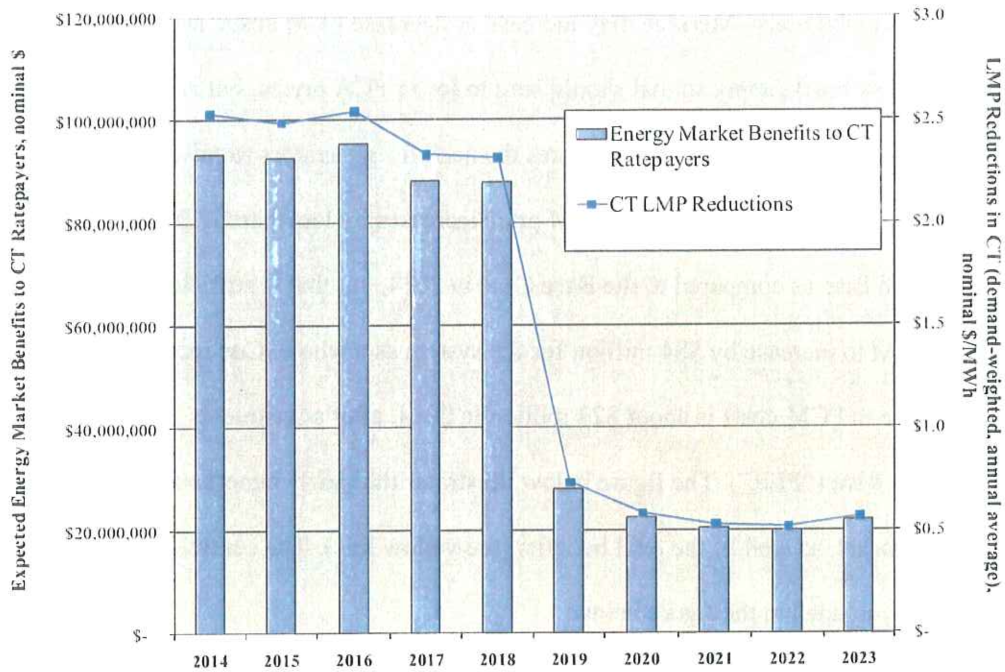
Note: These annual figures are based on mean of the thirty iterations.

Q. Please summarize the resulting energy benefits of Meriden to Connecticut ratepayers under the Base Case.

A. Based on the LMP reductions describe above, I calculated an energy benefit figure for Connecticut ratepayers. I focused solely on the benefits to Connecticut ratepayers given that Connecticut ratepayers would carry the entire cost burden of the contract with Meriden.[40] The figure below summarizes the expected annual average energy market benefits created by Meriden.

[40] In contrast, GSRP would be classified as a pooled transmission tariff and therefore the costs of GSRP would be shared or allocated across all New England ratepayers and therefore the proper benefit metric for a cost-benefit analysis of GSRP is system-wide benefits.

Figure 39. Meriden's projected energy market benefits (nominal $ millions and nominal $/MWh)



Note: These annual figures are based on annual average price reductions, equivalent to the mean of the thirty iterations. Furthermore, costs of the Meriden contract (CFDs) are not included in the figure above.

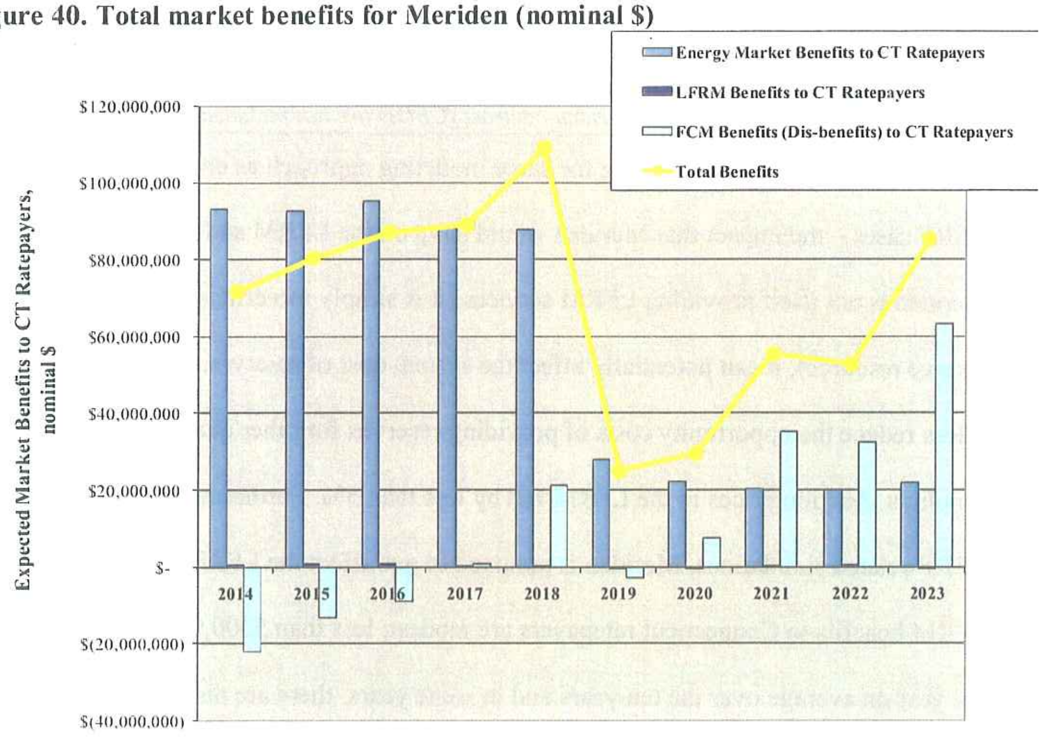
I then investigated – using the same modeling approach as employed in the GSRP cases – the impact that Meriden would have on the LFRM and FCM. Although Meriden is not itself providing LFRM services (it is simply too efficient to serve as a reserve resource), it can potentially affect the system cost of reserves. Lower energy prices reduce the opportunity costs of providing reserves for other qualified reserve suppliers. Auction prices in the LFRM fall by less than 5%. Furthermore, in contrast to GSRP-related simulations, Meriden is assumed to not affect the LFRRs. Therefore, the LFRM benefits to Connecticut ratepayers are modest: less than $300,000 of cost savings per year on average over the ten years and in some years, there are dis-benefits.[41]

The impact of Meriden on the FCM is in the opposite direction to energy

[41] Dis-benefits in LFRM are caused by changes in the merit order and clearing amounts for qualified resources.

benefits. In the first few years, Meriden actually increases the costs of the FCM to Connecticut ratepayers. As a priori to the modeling, Meriden's potential impact on the FCM is ambiguous– Meriden may increase or decrease FCM costs. Meriden introduces more (low cost) supply so that should lead to lower FCA prices, but at the same time, Meriden reduces LMPs and that creates the need for generators to raise FCM bids to offset lower energy profits. The FCM price increases by less than \$2.2/kW-year in the Meriden case as compared to the Base Case in 2014, but that is sufficient for the costs of the FCM to increase by \$84 million for the system as a whole. Connecticut's share of the increase in FCM costs is about \$22 million in 2014, after adjustments for the Peak Energy Rent ("PER"). The figure below illustrates the yearly benefits associated with each market, as well as the total benefits (see yellow line). The contract costs for Meriden are not included in the figure below.

Figure 40. Total market benefits for Meriden (nominal \$)

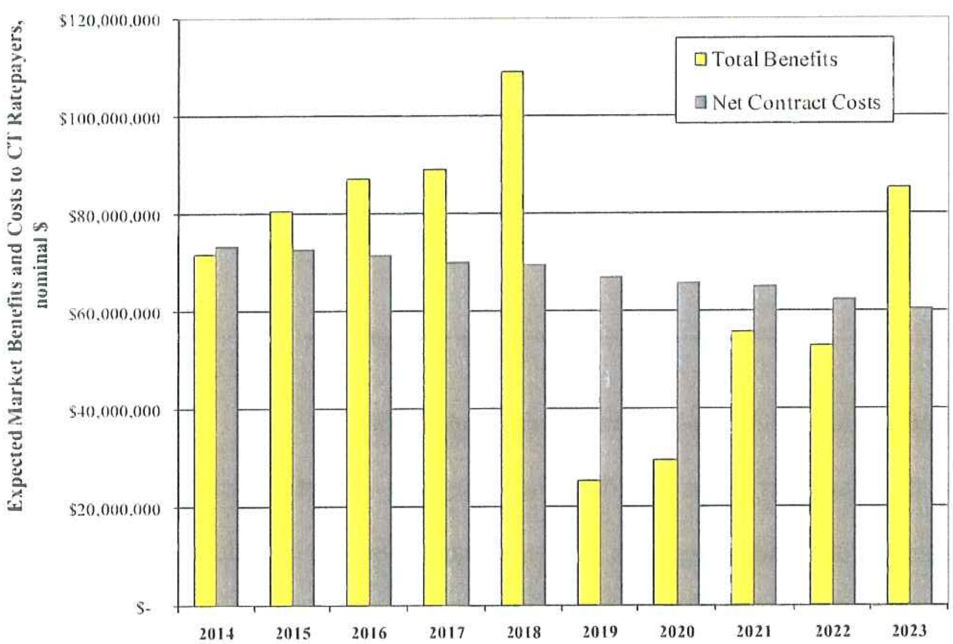


Note: These annual figures are based on annual average price reductions, equivalent to the mean of the thirty iterations. Furthermore, costs of the Meriden contract (CFDs) are not included in the figure above.

Q. What are the net benefits of the Meriden project under your Base Case?

A. A comparison of the net costs and total benefits reveals that Meriden's costs (net of the offsets) will exceed the market benefits it can produce for Connecticut ratepayers for four of the ten years. Meriden's ten-year PV for net benefits is $13.2 million at a 10% discount rate.

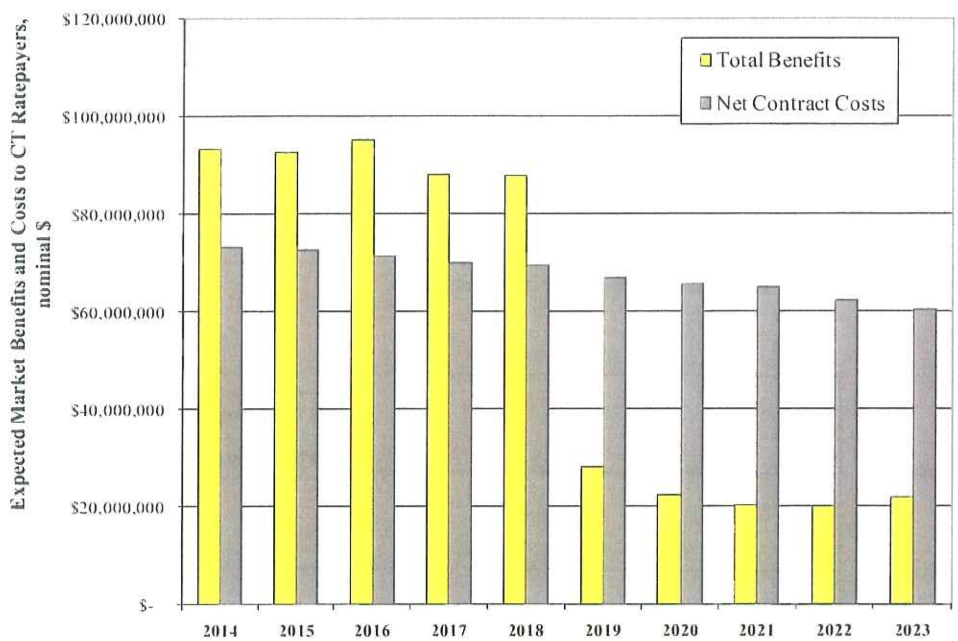
Figure 41. Projected Net Benefits of the Meriden project



Q. What would the net benefit be if you ignore the FCM and LFRM impacts?

A. As I described above, Meriden may produce dis-benefits (negative benefits) in some years in the FCM and LFRM because of the integrated nature (and trade-offs) between the energy market and the FCM and LFRM. If I exclude the impacts on the FCM and the LFRM altogether and focus solely on energy market benefits generated by Meriden, in five of the ten-years, costs exceed benefits and the PV over ten-year of net benefits is negative. Connecticut ratepayers would pay $22 million more in contracts costs as compared to energy market benefits.

Figure 42. Projected Net Benefits of the Meriden project without FCM and LFRM



Q. What would you conclude from the above analysis?

A. The above analysis shows that Meriden is marginal – at best – in terms of its economic merits to Connecticut ratepayers. I have not had the time to consider alternative scenarios and assumptions, but it is possible that a different set of assumptions could produce a larger positive benefit. But it is also plausible that a different set of assumptions would produce larger negative net benefits.

Q. Why do your projections differ from those prepared by La Capra in the CEAB's assessment?

A. I have not been able to review the detailed assumptions underpinning La Capra's economic analysis for the CEAB assessment, because the assumptions are not disclosed in the CEAB Evaluation Report, and because CEAB/La Capra have not as of yet provided those assumptions in response to CL&P's data request. I believe that the differences in results – especially in the later years of La Capra's assessment – will stem from differences in assumptions about supply and demand, and possibly fuel prices. I am specifically questioning the expanding trend in energy price reductions that was forecast and presented in the CEAB Evaluation Report. This trend may be partially conditioned on the supply assumptions, for example, La Capra appeared to limit generic new entry in Connecticut, which could bias the projected benefits.[42] However, without more information on the input and assumptions, I cannot definitively confirm that this is the sole or substantial driver of the presented price reductions.

Furthermore, it is notable that La Capra's assessment did not look at Meriden in isolation. As confirmed in a recent data response from CEAB, La Capra simulated the potential energy savings based on the combination of all RFP respondents and their projects (with a substantially bigger portfolio of MWs). A bigger portfolio of baseload generation and demand response is likely to produce a bigger price effect. At this time, the other CEAB RFP respondents have not submitted an application to the CSC for further consideration. And, because La Capra did not perform any analysis related solely to the Meriden project, I would suggest that the La Capra analysis for the CEAB Evaluation Report is no longer accurate for evaluation of Meriden's application at the CSC.

Q. Does this complete your testimony?

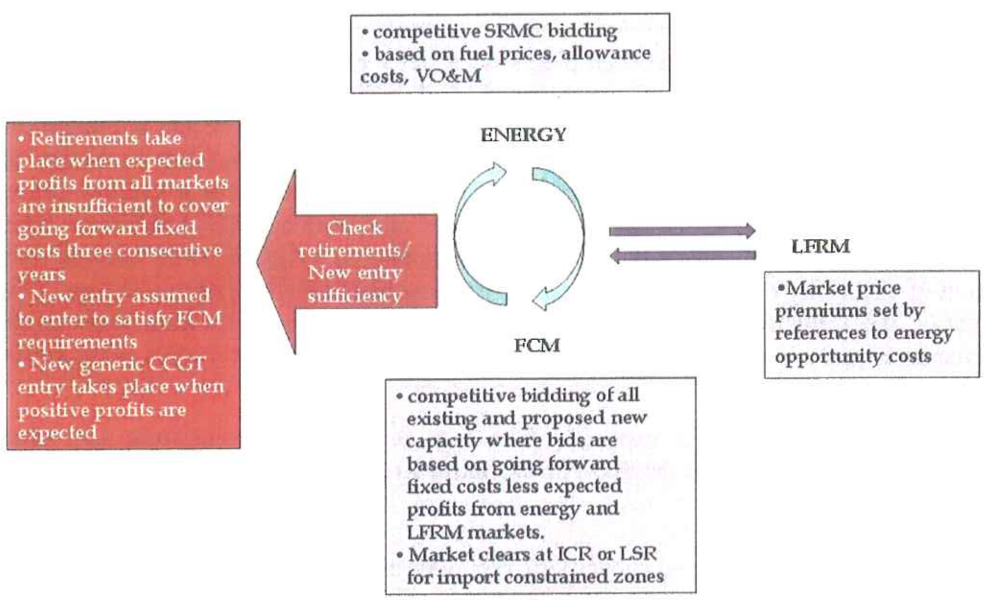
A. Yes.

[42] At page 49 of the CEAB Evaluation Report, it is stated: "[r]esources were allowed to be built in all New England zones except for the three modeled Connecticut zones, while retirements were allowed for all ISO-NE zones."

4 Appendix A: Overview of Modeling Tools

LEI employs a modeling suite that has been customized to represent the specific market rules currently in place at ISO-NE. The modeling suite consists of a network simulation model, POOLMod, a Forward Capacity Auction simulator, and a LFRM modeling tool set. I simulate the energy market, LFRM and the FCM on an integrated basis, which enables me to replicate economically rational entry and retirement decisions. The integrative approach is also better at capturing the key institutional and economic linkages between energy, locational forward reserve market and capacity market designs. For example, energy market dynamics underpin the forecast of LFRM prices, as the provision of operating reserves is linked to energy operations and the opportunity costs of foregone energy profits. In addition, expected energy profits impact generators' bidding behavior in the FCM. Figure 43 below illustrates the modeling process.

Figure 43. Flow diagram of energy, FCM and LFRM modeling

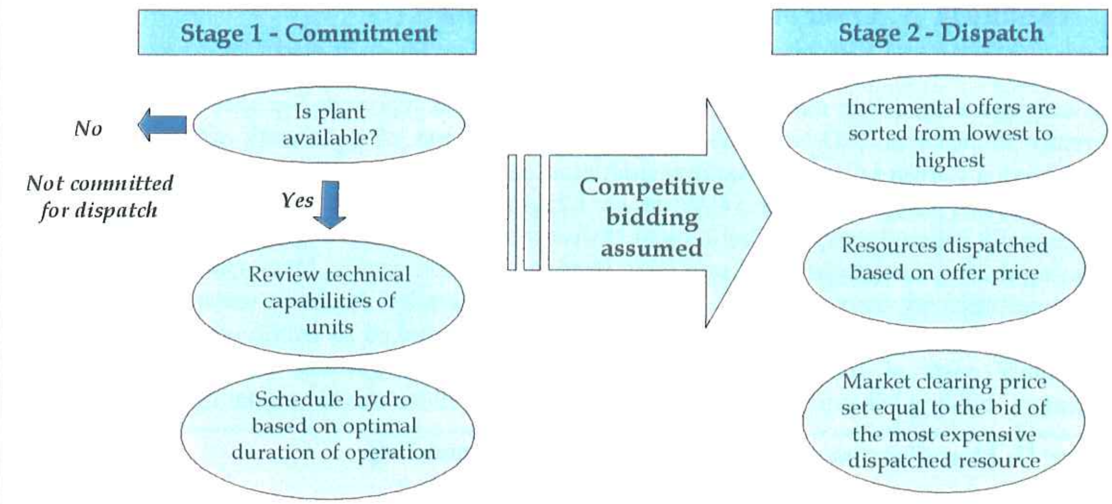


Energy modeling

LEI's proprietary simulation model, POOLMod, is used as the foundation for the electricity price forecast. POOLMod simulates the dispatch of generating resources on a least cost basis to meet projected hourly load, while also taking into account technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 44. POOLMod's two-stage process



POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing). Emissions are monitored by POOLMod, through tracking the amount of electricity output from each pant. Historical plant level emission rates are collected from Ventyx, the Velocity Suite and applied to the amount of electricity each plant produces. Hence, accurate micro-level emissions are used and aggregated to track system wide emissions output.

POOLMod's dispatch algorithms explicitly take into account both congestion and marginal losses. LEI has typically modeled the ISO-NE's Control Area on a zonal basis.

Capacity modeling

New England operates a centralized capacity market. Our modeling replicates the auction process embedded in the ISO-NE market through a simulation of expected supply-demand condition for the annual Forward Capacity Auction ("FCA"). Rational, competitive bidding behavior is assumed throughout the analysis. This means that suppliers are expected to submit their best, most competitive bid. The application of the competitive bidding assumption allowed me to approximate the multi-round descending clock auction design of the FCA with a single round auction in our modeling.

Existing generators are expected to offer their capacity into the capacity market at a price equal to their going forward fixed costs less expected profits from the energy and LFRM markets, while a new entrant is assumed to enter into the market when expected market profits[43] cover its all-in fixed costs. Appendix B provides a detailed discussion on the fixed cost estimation employed in developing the FCA bids for existing as well as new capacity.

[43] Market profit such as the sum of energy revenues, capacity market payments, and ancillary services payments, where applicable.

Once the bids of each generator are determined, they are sorted in ascending bid value, and an iterative process of selection starts clearing the lowest bidder until the total quantity of cleared supply reaches the predetermined Installed Capacity Requirement ("ICR"), the procurement target in the FCM.

The ISO determines the ICR for the New England market as a whole and Local Source Requirement ("LSR") in each designated Capacity Zone through the probabilistic loss-of-load expectation "(LOLE") analysis, ensuring that the system had adequate future capacity resources. The Capacity Zones are defined as the local areas that have insufficient local resources to meet their own local sourcing requirements. Thus, each year, the ISO evaluates the system for local import and export constraints, and defines those constrained areas as separate Capacity Zones. To the extent that a region or local area is unconstrained, it is included in the 'Rest of System' FCA. LEI's FCA simulator can take into account designated Capacity Zones, as specified by the user. Therefore, where transmission constraints do exist, capacity prices may be higher or lower in those constrained areas, depending on whether the areas are demand constrained or supply constrained.

In general, there are two driving factors in the capacity market which I refer to broadly as the income and substitution effects. As more resources are added to the market, the supply curve is extended to the right, displacing other resources and lowering capacity prices (resulting in a 'substitution effect'). Meanwhile, if the additional resources can impact energy market dynamics (either by lowering overall energy prices and consequently energy profits across the market or, at a minimum, by displacing peaking resources at the margin and therefore lowering that group's energy profits), they would be putting upward pressure on capacity bids. This is referred to as the income effect. Price impacts overall will depend on which effect dominates.

Locational forward reserves market modeling

The locational forward reserves market ("LFRM") is designed to provide New England with a market-based method for procuring non-spinning operating reserve services in advance through a reservation payment that is equivalent to the premium in a "call option." Given the technical qualifications required to provide the necessary 10-minute and 30-minute reserves products, the LFRM is unique in that participation by generators is effectively limited to a subset of all capacity in the region. In order to ensure that capacity is in fact available, generators awarded a locational forward reserve contract are required to offer into the Day-Ahead and Real-Time energy market at a price greater than the locational forward reserve strike price. In setting the strike price, ISO-NE targets flexible resources with high variable costs that would not typically be dispatched to provide energy, i.e. the units that can provide reserves most economically.[44] Therefore, the LFRM resources are typically not dispatched in the Day-Ahead and Real-time energy markets but are otherwise available and 'on reserve'.

Under the "call option" structure of the LFRM, the ISO-NE acquires the right but not the obligation to "call" on specific generation to provide energy for a period of time. The generators are obligated to be on "reserve" to provide such energy, if and when directed. The ISO thus effectively purchases insurance against contingency events that could otherwise result in system security breaches and/or high prices. In turn, the call-option premium provides a fixed revenue stream to those generating resources awarded a Forward Reserve Contract, which compensates them for the opportunity costs of providing the reserve service, including:[45]

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[44] Typically, ISO-NE sets the parameters of the LFRM obligation such that forward reserve resources are dispatched only 2-3% of the time.

[45] *See* February 6, 2006 ISO-NE ASM Phase 2 filing at FERC, Attachment 2, *Direct Testimony of Mark D. Montalvo*, p. 24.

1. expected foregone energy profits;

2. plus expected foregone commitment costs;

3. plus expected penalties;[46]

4. plus incremental O&M and/or capital investment;

5. plus expected ICAP clearing prices;

6. plus risk premium

Assuming satisfactory performance, a provider receives the forward reserve payment. The forward reserve payment is the auction price (in $/kW-month) for the applicable reserve product in the reserve zone divided by the number of on-peak hours in the applicable month. When obligations are met with reserves of higher quality, the reserve provider receives the forward reserve payment in addition to the real-time market revenue based on the difference in clearing price between the higher and lower quality product. In addition, if a forward reserve resource is dispatched, then it will receive the market clearing energy price for its output.

In modeling the LFRM, I attempted to proxy the market rules and ISO-NE practices: first, a clearing price is determined by modeling the opportunity costs of providing this ancillary service. These opportunity costs are based on the incremental system cost for servicing ISO-NE's locational forward reserves requirements ("LFRR") by zone (with and an estimated fixed adjustment factor designed to represent the probability of reserve use). Next, technically qualified reserve capacity is identified (subject to resource-specific technological ramping rates) and a clearing model determines how much MWs of capacity is awarded a LFRM contract for each qualifying resource, based on the merit order derived from net fixed costs.

Modeling details

I started the analysis with the ISO-NE's projections of LFRRs (from the 2008 RSP). These were used in modeling the LFRM under the Base Case (without GSRP) and in the Base Case with Meriden. It is notable that ISO-NE's forecasts in RSP 2008 take into the SWCT Reliability Project Phase II and NSTAR 345 kV Transmission Reliability Project. I therefore reflected the impact that these projects are expected to make on the LFRRs. However, ISO-NE did not publish LFRR projections for GSRP because it is outside the typical forecast timeframe for such analysis. Although, ISO-NE has indirectly recognized that the NEEWS projects will decrease the needed reserves in the CT Zone: "The Greater Connecticut load pocket appears to need an additional 225 to 325 MW of fast-start resources from summer 2008 through 2012, a period preceding the expected addition of the NEEWS project[s]."[47]

I then needed to estimate the adjustments to LFRR for GSRP. The fundamental issue, based on observed experience with other transmission projects, relates to how much of the additional transmission capacity is going to be available for reserves (in other words, what portion of the 200 MW being added to the Connecticut Import interface with GSRP will not be expected to be utilized for energy?).

I began with ISO-NE estimates for CT LFRR, which uses the 95th percentile of an ISO-NE estimated distribution of potential LFRRs based on historical data. In effect, I took the ISO's

[46] There are two types of penalties in the LFRM: Failure-to-Reserve (FOR) penalty and the Failure-to-Activate (FOA) penalty. The FOR penalty occurs if the supplier fails to fulfill its reserve obligation either by insufficiently assigning resources or by keeping the resource(s) unavailable. The FOA penalty occurs if the supplier fails to follow the dispatch instructions during contingency event.

[47] ISO-NE, RSP 2008, p. 7

estimates of the distribution of LFRRS in the analysis, and then reduce them to account for the incremental reserve capacity created through GSRP.[48]

The amount of additional transmission capacity from NEEWS is static; however the energy flows are not. Hence before adjusting the LFRR distribution with some fixed constant, I studied the increase in energy flows stemming from each phase of NEEWS. I observed from the energy modeling that a lot of the incremental capacity could be used to import reserves because it was typically not used for energy. I further observed that in general – given the nature of the modeling and our 'base case', weather normalized assumptions – our distribution of energy flows on the CT import interface (a proxy for the 'unused' incremental transmission capacity) was much more uniform, or clustered around the mean, whereas the actual observed flows exhibit a pattern with a higher tendency to the limit. In effect, in our modeling is not capturing all the stochastic effects of the market and their impacts on flows in a given hour. This is in fact consistent with the assumptions and structure of the long term analysis, where the objective is to capture 'most likely' or 'average trends.' I therefore calculated the 'average' of the energy flows associated with each phase of NEEWS and converted that into an 'average' of the incremental transmission capacity that would be available for reserves. Once the average energy flows were estimated, they were subtracted from additional transmission capacity created by each phase of NEEWS to get the shift factor for decreasing the Connecticut LFRRs.

For example, I began with ISO-NE values of 700/600 for CT (this assumes just the RIRP), see Figure 45 below. These LFRRs were generated from ISO-NE's forecast estimates of reserve requirements at the 95th percentile. However, once I moved to GSRP, the CT import interface capacity limit increases by 200 MW. Our estimates show that on average, GSRP adds an additional 195 MW of reserve support for Connecticut, referred to as "ERS" by ISO-NE in 2014. Therefore the LFRR for Connecticut zone in 2014 with GSRP declines to 505 MW. The figure below presents the adjustments to Connecticut's LFRRs for the entire 10 year horizon and over the 30 seeds.

Next, the clearing price was determined by modeling the opportunity costs of providing this ancillary service (i.e., LFRRs) from the system's perspective. The opportunity costs were estimated for on-peak hours and converted into a LFRM "premium" – the component of the auction clearing price above and beyond the capacity price – in effect, the profit for LFRM services that generators demand.

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48 The LFRR are based on the following equation:

Locational Forward Reserve Requirement (LFRR) = Max[N-2 Gen, N-2 Line] – ERS

where the ERS follows the equation:

ERS=LIMITN-1 – [Peak Loadi – Local Generationi] , where i represents the ith day

The external reserve support (ERS) is equal to the amount of transmission capacity found on the first contingency interface limit ($LIMIT_{N-1}$) after accounting for all energy flows on the transmission interface historically (Peak $Load_i$ – Local $Generation_i$).

Figure 45. Projected annual LFRRs for CT for RIRP and GSRP (MW)

Base Case	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	505	505	506	506	506	506	506	505	506	506
Meriden	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	502	502	502	502	502	503	503	502	502	502
Nuclear Outage	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	606	607	612	612	616	625	623	617	615	618
High Fuel	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	505	505	505	505	504	506	505	504	505	505
More retirements, more renewables	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RIRP	700	700	700	700	700	700	700	700	700	700
GSRP	505	505	507	507	507	510	510	508	509	510

Note: annual LFRR are calculated for each of the thirty iterations individually, but are averaged here for presentation purposes.

Lastly, not all capacity in the market gets paid LFRM revenues given the technical and economic constraints. I estimated the qualified capacity portion for each generator according to a series of tests associated with the unit's fuel type, prime mover type, heat rate, ramp rate, etc. I combined the compiled information about qualifications vis-à-vis the 10-minute and 30-minute requirement[49] with the unit's summer capacity to obtain the total qualified LFRM supply from each unit. A plant's LFRM capacity is determined by meeting both constraints. This list of LFRM qualifying capacity is then converted to a supply stack based on the merit order derived from fixed. The cumulative sum of all qualified capacity below the projected LFRR for a particular zone is then assumed to clear the auction and is then paid LFRM revenues.

[49] In our modeling, I did not differentiate between 10-minute and 30-minute product, as prices have typically not diverged in the past given the abundance of 10-minute qualified capacity.

5 Appendix B: Summary of Modeling Assumptions

5.1 Base Case Overview

This modeling exercise revolves around a "Base Case". The Base Case was first constructed to represent an outlook for the 'expected' market conditions, based on a set of 'most likely' input parameters. Then, a transmission project or a generation project was overlaid on the Base Case. A comparison of the market price outcomes with and without the transmission or generation project against the Base Case allows me to then isolate the economic benefits (or costs) of the transmission or generation project.

Under the Base Case modeling, LEI simulated prices that I would characterize as long term market trends. Therefore, the Base Case was specifically designed to capture long-term trends – and not the oscillations that are likely to actually occur around the long run average. The approach used to achieve this goal was accomplished through various inputs assumptions.

- **Load:** Starting from demand side, hourly demand projections were based on ISO-NE's 50/50 (weather normalized) demand forecasts from ISO-NE's 2008 *Capacity, Energy, Loads and Transmission* ("CELT") report.
- **Supply:** On the supply side, LEI first have taken the current set of existing generation, based also on the 2008 ISO-NE CELT report. LEI also included the known projects that already awarded firm contracts with IOUs. These projects are highly likely to come online based on its announced schedule as the firm contracts effectively secure their financing. Short term entry also included projects with I.3.9. approval, already under construction, or highly likely to get their capacity uprates. In the longer term, the model assumed merchant generators would make "just-in-time" capacity investment decisions, given signals from the market.
- **Balanced Supply-Demand:** Even though there was excess supply in the capacity market over the short term (as a result of the capacity obligations confirmed in the first and the second FCAs), LEI generally strives towards a balanced supply-demand situation in the longer term, consistent with the character of this "Base Case" forecast. For example, expected new entry was synchronized with demand in the long term and with ISO-NE's reliability reserve requirements (as well as renewable portfolio standards set by state regulators). In addition, new entry decisions were conditioned on modeled outcomes such that additional new entry will be introduced if it is economically feasible given the simulated market dynamics, i.e. revenues from energy, capacity and other markets/programs is sufficient to cover fixed costs. The model also endogenously chose and evaluated exit decisions. Plants were assumed to exit the market, if their revenues could not cover the going forward fixed costs, consistent with economically rational behavior. The combination of a rational entry decisions and rational exit decision allows the model to create convergence to balanced supply-demand state over the long term.
- **Hydrology:** For hydro plants, the historical hydro production in New England was reviewed and a weather normalized hydrology pattern for the hydroelectric generation profile was applied.
- **Fuel prices:** For the fuel price forecast, NYMEX futures accessed as of October 14th 2008 and EIA's long-term forecasts (from the 2008 *Annual Energy Outlook*) were used.[50]

[50] Source: US Energy Information Administration, *2008 Annual Energy Outlook Assumption*, table 3, 14 and 19.

- **Transmission:** The transmission topology and thermal limits on key interfaces was based on existing operating limits, except for those interfaces where upgrades are already under construction or otherwise planned/approved by ISO-NE. Transmission expansions of currently known and approved projects, per the announced schedules in the 2008 RSP, are assumed to be completed on time; these include the Southwest Connecticut Phase II (with in-service date of 2010) and the Maine Power Reliability Program ("MPRP") (with in-service date of 2013).[51]
- **Generator bidding:** Lastly, perfectly competitive bidding behavior was assumed throughout the modeling exercise. In the energy markets, this translates into a bidding rule where generators are constrained to bid at their short-run marginal costs. In the capacity and forward reserve modeling, generators were expected to bid their minimum going forward fixed or opportunity costs.

An overview of the assumptions used in the Base Case is shown in the table below. These assumptions represent the best available information at the time of modeling commencement in the fall of 2008.

[51] Source: ISO-NE RSP 2008. Other announced transmission projects within New England and announced/proposed projects that would expand the interties into New England were not included in the Base Case and scenarios due to state of uncertainty surrounding such other projects.

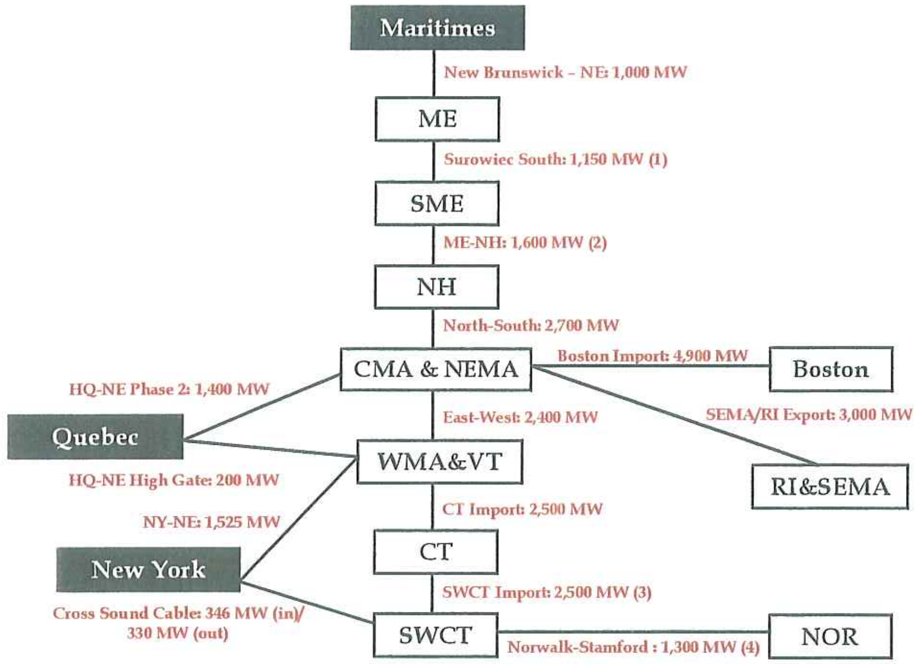
Figure 46. Summary assumptions for the Base Case

Assumption		Base Case
Network Topology		In our market simulation, we divide ISO New England Control Areas (ISO-NECA) into ten regions, corresponding to the thirteen sub-regions used by ISO-NE, while taking historical congestions between key regions into consideration.
Demand		The 2014-2017 sub-regional hourly load profile is based on ISO-NE's projected hourly demand by zone. Major assumptions and conditions, including weather, are assumed to approach or approximate long run averages. 2018-2023 data was modeled according to historical growth trends (based on the previous 2 years).
Interface		Our assumptions on the interfaces are consistent with major ISO-NE congestion and operating constraints. The transfer limits are based on ISO-NE and NU assumptions.
Fuel (natural gas)	2014-2020	NYMEX forward prices plus the five-year price differential between the commodity price at the Henry Hub and the Boston Citygate.
	2021-2023	Annual escalation of 3.5% linked to historical commodity price inflationary trends.
Other fuels		• The starting point for the distillate oil price forecast is based on the heating oil forwards from NYMEX. From 2009-2011, it follows the NYMEX light crude oil trend, then grows at the same rate as natural gas to maintain the same gas and oil dispatch merit order. The residual oil price forecast was derived from an estimate of the distillate/residual oil ratio (which is ~65%) based on the 5-year historical 2003-2007 New York harbor distillate/residual ratio growing at a rate of 2% per annum, based on EIA's Annual Energy Outlook (AEO) inflation rate. The assumed crude oil price in 2009 is US$84.2/barrel. • We rely on plant-specific coal price outlooks since each coal plant has different sulfur content levels and different contracts for price and transportation, resulting in different delivered fuel costs. Our coal price assumptions are based on the 2007 average delivered price to each plant escalated to nominal terms using the annual rate of change implied in the coal price index and inflation rate from EIA's AEO 2008 at 2% per annum.
New Entry		• For near term entry, we incorporate known projects that had a high likelihood of proceeding to commercial operation but commercial availability is pushed back by six months to a year from announced dates in order to reflect more realistic project completion dates. These projects include: projects that are already under construction, or have I.3.9 approval, or highly likely to get their capacity uprates approved, such as Cos Cob and Millstone or having contract awards. • In the longer term, our modeling incorporates generic new entry by fuel/technology, following three criteria guiding the amount of new capacity: a) new generic renewables to meet each state's Renewable Portfolio Standard (RPS) targets; b) requirements to meet ISO-specified amounts for reliability purposes (Installed Capacity Requirements); and c) additional entry possible under the economic rational rule if a generator can cover its all-in fixed costs from energy capacity and reserve markets combined.
Retirements		• Our model reflects economic retirements. We identify specific plants to test if they are able to cover minimum going forward fixed costs over three years. • We assume repowering at critical sites like Norwalk Harbor and Bridgeport Harbor.

5.2 Market topology

In our market simulation I divided the ISO-New England Control Area into ten regions, corresponding to the thirteen sub-regions used by ISO-NE for planning analysis, but taking into account the transmission interfaces that have experienced the most binding congestion historically and explicitly recognizing the transmission interfaces impacted by GSRP. The topology of our New England market model is presented in figure below.

Figure 47. New England system topology modeled under the Base Case



Note:

(1) Suroweic South: Increases to 1,875 MW in 2013

(2) Maine to New Hampshire Interface: Decreases to 1,575 MW in 2011; Decreases to 1,550 Mw in 2012; Decreases to 1,525 Mw in 2013; Decreases to 1,500 MW in 2014; Decreases to 1,475 MW in 2015; Decreases to 1,450 MW in 2016

(3) SWCT Imports: Increases to 2,700 MW in 2010

(4) Norwalk-Stamford: Increases to 1,650 MW in 2010

Regions: ME=Maine; SME=Southern Maine; NH=New Hampshire; CMA&NEMA=Central Massachusetts and Northern Massachusetts; WMA&VT=Western Massachusetts and Vermont; BOSTON= Boston; CT=Connecticut; SWCT = Southwest Connecticut; RI&SEMA=Southeastern Massachusetts and Rhode Island; NOR= Norwalk

Modeled transmission enhancements

As briefly discussed above, I included the transmission enhancements of the Southwest Connecticut Phase II project. This project, which includes a 70-mile 345 kV circuit from Middletown CT to Norwalk and a pair of new 115 kV lines from Norwalk to Glenbrook, CT,[52] will increase the transfer limits of Southwest Connecticut import and Norwalk-Stamford interface from 2,350 MW to 3,650 MW and 1,300 to 1,650 MW in 2010, respectively.[53]

I also incorporated the Maine Power Reliability Program ("MPRP") in our modeling. The MPRP consists of approximately 245 miles of new 345 kV transmission line, 74 miles of new 115 kV transmission line, 10 miles of rebuilt 345 kV transmission line, 155 miles of rebuilt 115 kV

52 ISO-NE, 2008 RSP, 16 October 2008, p 10.

53 ISO-NE Economic Studies Working Group, "Maine Power Connector Economic Analyses," May 22, 2008, slide 14.

transmission line, and upgrades to Central Maine's existing substations.[54] I assumed that the termination point for the MPRP will be in Maine.[55] Thus, only the Suroweic South interface will be affected in our topology; and this will lead to an increase in the transfer limit of the Southern Maine ("SME") to Maine ("ME") (and vice versa) by 725 MW[56] from the existing 1,150 MW[57] to 1,875 MW with completion of MPRP (in 2013).

External markets

Externally, ISO-NE is well interconnected with surrounding regions, with ties to the New Brunswick, Quebec, and New York markets. I did not model power plants in regions outside New England explicitly. Instead, resources in Maritimes, as well as in other interconnected regions (i.e., New York and Quebec) were modeled on an aggregate or composite supply curve basis. The figure above also details the external interfaces with their respective thermal limits employed in our model (note that these thermal limits are only binding if the intertie is fully utilized). I did not presume that the interties would be fully utilized, but rather let the model make the economic choice between local resources and external resources given defined marginal costs.

I expect the imports from Quebec to continue into the future, and to be priced consistently with a pumped storage dynamic, shadow pricing off gas-fired resources. Exports to New York through Cross Sound Cable are also expected to continue at historical levels due to the projected continuation of tight in-city reserve margins (New York City and Long Island). On the other hand, due to the 18-month refurbishment of the Point Lepreau nuclear unit in New Brunswick, I expect that imports from Maritimes will decline during the refurbishment period in the short term, but after the Point Lepreau plant is back in service, projected to be by late 2009 or early 2010,[58] more off-peak flows from Maritimes are expected. In addition, several renewable projects are proposed in the Maritimes to further bring green power to the New England system, which I modeled as increased, relatively low-cost resources from the Maritimes. However, these resources would flow through the existing system and therefore would be limited by existing transmission constraints from New Brunswick to Maine, Maine to Southern Maine, and Southern Maine to New Hampshire.

Transfer interface assumptions related to GSPR project

GSPR projects impact both the Connecticut Import and the East-West interfaces. According to NU-provided assumptions, the Connecticut Import and East-West interface increases by 200 MW with the addition of the GSRP.[59] NU provided more detailed interface assumptions to include in the modeling with respect to the CT Import interface:[60]

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[54] "Central Maine Power and Public Service of New Hampshire Request for Certificate of Public Convenience and Necessity for the Maine Power Reliability Program," 01 July 2008, p. 20.

[55] This information regarding MPRP was developed in conjunction with discussions with CL&P on November 14, 2008.

[56] Federal Energy Regulatory Commission, "Order Conditionally Granting Petition for Declaratory Order," Federal Docket No. EL08-74-000, Issued October 20, 2008.

[57] ISO-NE Economic Studies Working Group, "Maine Power Connector Economic Analyses," May 22, 2008, slide 14.

[58] See http://poweringthefuture.nbpower.com/en/Default.aspx

[59] 700 MW with the addition of the Interstate, and 1,100 MW with the addition of the CCRP.

[60] This information was provided to us by CL&P on October 15, 2008.

- The basic CT Import limit of 2,500 MW was reduced by 800 MW for the spring (months of March-May) and fall (months of September-November), as these are the period when maintenance on major 345-kV and other facilities typically takes place and ISO-NE operates under reduced transfer capabilities.

- The Connecticut Import limit was reduced by up to another 500 MW when the New York exports (excluding Cross Sound cable) are more than 1,000 MW or when the New York imports (excluding Cross Sound cable) are more than 1,300 MW.

- Furthermore, **both** the Connecticut Import and the East-West interface limit were reduced by 500 MW whenever all Lake Road units are not in-service.

These reductions are additive if a combination of the above conditions exists. However, the maximum reduction would only be at 1,000 MW at a single time for the CT Import limit.

Transmission loss rates

Transmission losses were also incorporated in our energy market modeling. Marginal transmission loss factors were calculated by dividing the historical hourly real time loss component by the energy component of LMP by RSP zone. The figure below summarizes the average transmission loss factor derived from actual LMP data from August 2007 through September 2008. Conservatively, I did not adjust the loss factor for the improvements expected from SWCT Phase II, MPRP, and GSRP.

Figure 48. Transmission loss rates

Interface	Average Loss	Average LMP		Loss Factor
Norwalk/Stamford, SWCT Import, CT Import (Into CT), East-West (CT to Central Mass/NEMA)	1.91	$	84.54	2.3%
Suroweic South, ME-NH (NH to Southern Maine)	-3.49	$	76.85	4.5%
Boston Import	-0.37	$	81.16	0.5%
ME-NH (Southern Maine to NH), North South (NH to Central Mass/NEMA)	-0.78	$	80.42	1.0%
SEMA/RI Export (Central Mass/NEMA to RI)	-0.90	$	80.29	1.1%
SEMA/RI Export (RI to Central Mass/NEMA)	-0.53	$	82.21	0.6%
East-West(Central Mass/NEMA to CT)	0.55	$	81.95	0.7%
CT-Import (CT to CMA/WMA)	0.61	$	82.14	0.7%

Source: Ventyx, the Velocity Suite

5.3 Generation resources in New England

Existing generation resources

The existing capacity in the station database was calibrated primarily based on the latest official data from the ISO-NE (like the Capacity, Energy, Load and Transmission Report ("CELT") and the *2008 RSP)*, and supplemented by documents provided by NU and historical operational and financial date from Ventyx, the Velocity Suite, as well as generation resources data from utilities, surveys of independent power producers, and our own independent research.

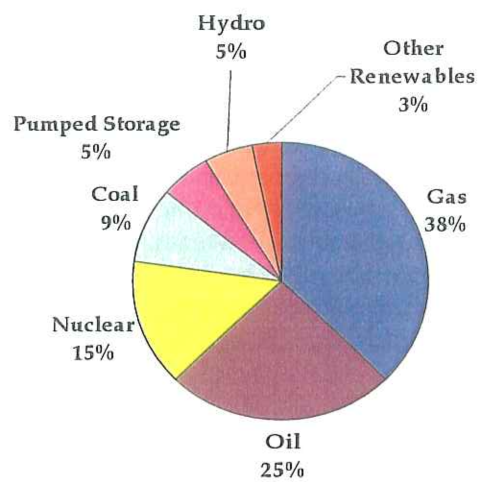
Figure 49. Summer Claimed Capability of existing generation, by fuel type and sub-region (MW)

	ME	BOSTON	CMA/NEMA	VT/WMA	CT	SWCT	NOR	NH	RI/SEMA	Total
Other Renewables	309	75	3	71	123	65	-	211	91	947
Coal	-	312	-	144	181	372	-	528	1209	2745
Oil	867	1256	30	384	1924	293	503	484	1737	7476
Natural Gas	1532	1662	99	1336	115	1215	-	1166	4857	11983
Nuclear	-	-	-	604	2021	-	-	1245	677	4548
Hydro	587	8	24	2094	24	110	-	476	-	3324
Total	3295	3313	156	4633	4387	2056	503	4110	8571	31023

Source: 2008 ISO-NE CELT

According to the latest 2008 CELT, the total summer installed capacity in New England is 31,024 MW.[61] More than a third of the capacity comes from gas-fired plants and a quarter from oil. The remaining installed capacity comes from nuclear (15%), coal (9%), hydro and pumped storage (10%), and other renewables such as wind and biomass.

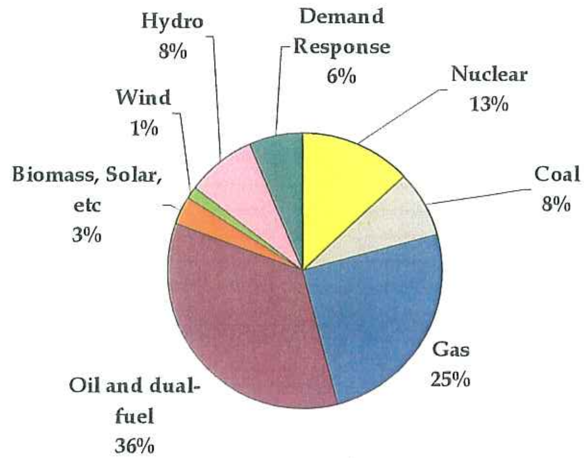
Figure 50. Installed summer capacity in New England, 2008



Based on the model forecast year for 2014 and taking into account existing capacity and short-term new entry given approved or under construction plants, thirty-six percent (36%) of New England's generation portfolio is expected to be oil and dual-fired plants, with a large contingency of gas-fired plants supplying much of the remaining installed capacity (25%). The nuclear (13%) and hydro (8%) facilities contributed substantially to helping the natural gas plant serve the region's internal base load demand, as well as producing surplus power for export under favorable hydrological conditions. Note that the dual fired plants include natural gas plants which also burn oil. In terms of capacity, coal plants played a lesser role, while the recent popularity of biomass and wind projects continued to expand the role of alternative generation resources.

61 Source: 2008 CELT. This number excludes net purchases from external markets.

Figure 51. Fuel mix by installed capacity in New England, 2014 estimate for Base Case



Note 1: Oil and dual fuel category includes power plants that primarily use natural gas but also have the capability to burn oil.

Note 2: Demand response has been uprated by 8% and wind has been derated by approximately 28%, consistent with FCM Market Rules

Short-term new entry

For short term entry, known projects were incorporated into the supply mix, if they were fairly certain. For example, based on extensive research of publicly announced new entry, planned capacity additions were considered. Project status was critically considered. For example, projects that have certain approvals and/or power purchase contracts, or those plants that have begun construction were classified as 'fairly certain' new entrants and therefore included in the Base Case (albeit, sometimes with a delay to their announced start date). Typically, start of commercial operations was pushed back by six months to one year of the announced commercial online dates in order to take into account the actual experiences in project delay as well as the residual effect of the current financial downturn.

For comparative purposes only, the figure below shows the announced new entry in New England based on the most recent ISO-NE interconnection queue. A total of 20,329 MW of new capacity is active in the ISO-NE interconnection queue as of April 19th, 2009. Most of these proposed new capacity projects are being planned to be built in Rhode Island and Western Massachusetts ("WMA"). Despite breadth of activity, ISO-NE has recently warned that the region has recently experienced the withdrawal of a significant portion of projects in the queue before the projects were built, because of project cost escalation, financing, siting, and permitting problems.[62] It is important to keep in mind that the table below (Figure 52) is based on the entire 2008 ISO-NE interconnection request queue, which occasionally includes multiple requests from the same generation unit if more than one configuration is proposed. This then results in an inflated 'perception' about the total planned new entry capacity in New England. I can confidently say that only a portion of this 20 GW will be built in the next fifteen years. Therefore Figure 52 is not a summary of the modeled new entry, but rather a summary of proposed new entry.

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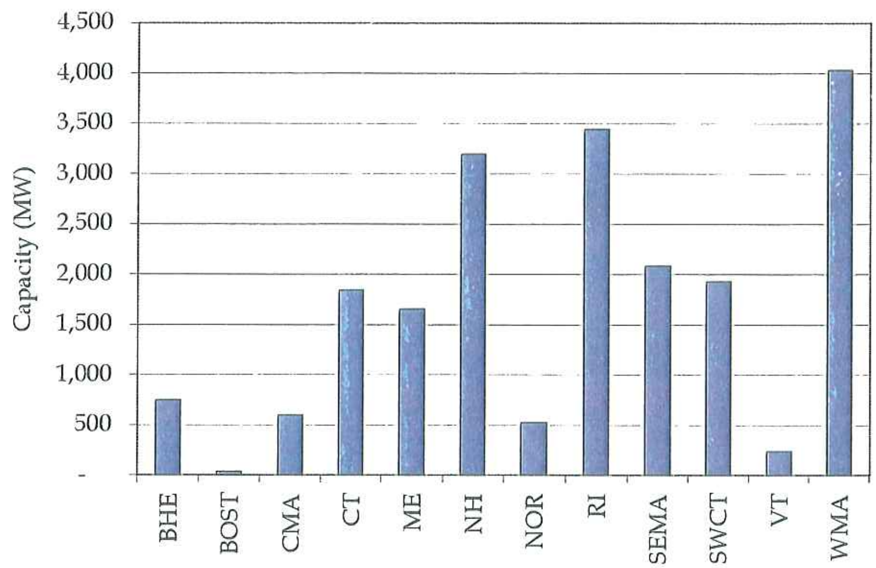
62 ISO-NE, *2008 RSP*. October 18, 2008, p.96.

Figure 52. Announced plans for new capacity in the ISO-NE Interconnection Queue



Source: ISO-NE Interconnection Queue as of April 19, 2009

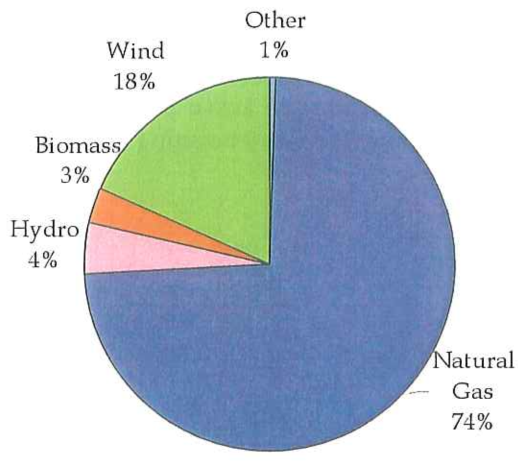
As already discussed, the short term project-specific candidate pool for the Base Case was further refined from the announced new entry list and based on detailed research on status of individual projects by LEI. Figure 53 and Figure 54 show the plants that are currently under the Interconnection Queue and have I.39 approval. In addition, projects that were identified as having contract awards (such as the 2006 CT RFP winners, 'Project 150' winners, and 'cost of service' peaking generation RFP winners) were included. I also explicitly included new supply-side capacity that cleared in the second forward capacity auction ("FCA") through generic capacity additions.

Figure 55 on page 80 is a list of new plants that were explicitly include in the modeling. These plants are primarily consisting of projects that are already under construction, or have I.3.9 approval, or highly likely to get their capacity uprates approved, such as Cos Cob and Millstone. The list also includes projects that have been awarded contract.

Figure 53. Summary of announced new entry in New England from the Interconnection Study Queue with I.3.9 Approval, based on region and projected year of commercial operation (MW)

Region	2009	2010	2011	2012	2013	Total
BHE	28					28
BOST	18					18
CMA		99	311			410
CT		872	108			980
ME	65	66				131
NH	169					169
NOR		204				204
SEMA	132	462		350		944
SWCT	96	675				771
VT	40					40
WMA	2	30			55	87
Total	**549**	**2,408**	**419**	**350**	**55**	**3,780**

Figure 54. Summary of announced new entry in New England from the Interconnection Study Queue, projects with I.3.9 Approval and commercial operating date of 2009-2013



Note: The natural gas category includes plants with dual fueled capability

Source: ISO-NE Interconnection Queue, April 19, 2009

Figure 55. Modeled short-term project-specific additions under Base Case in New England, 2009-2013

Year In	Plant	Region	Capacity (MW)	Fuel Type
2008	Indeck Alexandria Energy Center	NH	18.1	Biomass
2008	Kimberly Clark	CT	21.6	Natural Gas
2008	L'ENERGIA	CM	74.0	Natural Gas
2008	Pine Tree LFGTE	ME	2.9	Biomass
2009	Ameresco EE 1	CT	1.0	Biomass
2009	Cos Cob Redevelopment	CT	45.8	Natural Gas/ Distillate
2009	interconnectionI39_WIND_ME	ME	60.0	Wind
2009	Barre Mass Landfill Gas	MV	1.6	Biomass
2009	Millstone Point uprate	CT	80.0	Nuclear
2009	Project 150 Round2-Clearview Laurelbrook	CT	3.0	Biomass
2009	Project 150 Round2-DFC-ERG Milford	CT	9.0	fuel cell
2009	Project 150 Round2-EMCOR-Stamford Hospital	SW	4.8	fuel cell
2009	Project 150 Round2-EMCOR-Waterbury Hospital	NR	2.4	fuel cell
2009	Project 150 Round2-South Norwalk	NR	32.0	landfill gas
2010	Ameresco EE 2	CT	1.0	Biomass
2010	Mirant Kendall Jet 2_I39	NB	18.0	Distillate/Jet Fuel
2010	interconnectionI39_WND_ME_partI	ME	65.0	Wind
2010	Thomas A. Watson Generating Station	SR	115.0	Natural Gas/ Distillate
2010	Sheffield Wind Project	MV	40.0	Wind
2010	GenConn-Devon Repowering	SW	200.0	Natural Gas/Residual
2010	Project 150 Round1-Tamarack Energy_In	CT	15.0	Biomass
2010	Project 150 Round2-Clearview-Kofkoff Egg Farm	CT	30.0	Biomass
2010	Project 150 Round2-Plainfield Renewable Energy	CT	37.5	Biomass
2010	Waterbury Generating	CT	96.0	Natural Gas
2011	Ameresco EE 3	CT	3.0	Biomass
2011	Cape Wind	SR	420.0	Wind
2011	Lowel Power Generators IQI39	CM	99.0	Natural Gas/ Distillate
2011	interconnectionI39_WND_ME_partII	ME	65.5	Wind
2011	Kleen Energy	CT	620.0	Natural Gas
2011	GenConn-Middletown Repowering	CT	200.0	Natural Gas/Residual
2011	Waterside Power	CT	207.0	Distillate
2012	interconnectionI39_NG_SR	SR	425.0	Natural Gas
2012	Billerica Power_NG_OIL	SR	341.0	Natural Gas/ Distillate
2012	Dartmouth Power Addition_NG_KR	SR	24.0	Natural Gas/ Distillate
2012	interconnectionI39_WDS_WMA	MV	55.0	Biomass
2012	New Peaker in New Haven	CT	130.0	Natural Gas
2012	New Wind	MV	310.0	Wind
2013	New Biomass	NR	25.0	Biomass
2013	New Wind	CM	96.0	Wind
2013	New Wind	NB	135.0	Wind
2013	Project 150 Round3	CT	25.8	Biomass
Total			4155.0	

Long–term new entry

In the longer term, the modeling incorporated generic new entry. Although a specific project associated with an interconnection request was not named, the generic long term new entry took into account the practical implications of the trends in interconnection requests (for example, choice of location for generic new entry was guided by locations for candidates in the interconnection queue, as described in Figure 52 above). There are three criteria guiding the amount of new generic capacity added to the New England system under the Base Case in the longer term: Renewable Portfolio Standard ("RPS"), reliability requirements and economics.

The modeling began by using the first and second criteria to determine the quantity of new entry and then the results were refined and calibrated to include the third criterion, taking into account revenues from both the energy and capacity markets. The mix (or type) of entry is a function of market economics (i.e. profitability of generators) and policy priorities (i.e. renewables to meet RPS), as well as political realities (i.e. coal is unlikely to be a realistic candidate for these markets given the lack of commercial capability to carbon sequester in New England even though it could be competitive at high gas prices). The location of entry is a function of market economics and preferences observed from the Interconnection Queue requests to date.

The first criterion that guided the planning of generic new entry in the modeling relates to the Renewable Portfolio Standard ("RPS") targets across the New England states. The RPS represents state-level regulation which sets renewable targets on new and existing generating units by technology and year the unit was built. The general rule is to determine the minimum requirement for renewable capacity (based on consideration of the state-specific RPS targets, projected energy consumption, and some notional understanding of internal versus external RPS-eligible renewable capabilities). While the RPS targets are set with regard to different uses for different states, the method used to get capacity targets in megawatts follows that of ISO-NE's *2008 RSP*, which recognizes that the RPS target levels are with respect to forecasted energy use.[63] Some states have passed RPS targets which permit existing renewable units to contribute. In these cases, before calculating the amount of new renewable capacity to be counted towards a target, the existing capacity targets were subtracted from the overall capacity implied by the calculations. In doing so, the implicit assumption is that existing renewable units are approximately equal to the existing renewable targets set by the RPS in 2008-09 (which is consistent with REC price trends observed recently) as well as the NEPOOL GIS certifications for the first quarter and second quarter of 2008.

Once existing plants have been netted out of the annual forward renewables requirement, the incremental renewable generation needed in each year was derived. The generation shortfall was then converted into a measure of renewable capacity. In effect, the Base Case modeling presumed that new entry evolves in the medium to longer term to sufficiently meet current known RPS targets. ISO-NE's *2008 RSP* estimated that 8,404 GWh of annual electricity would be required to come from new qualified renewable units by 2012, and 13,888 GWh by 2016, which includes Vermont's voluntary targets.[64,65] Assuming that there has been satisfactory compliance with 2008 requirements for new renewable resources in New England, then this effectively creates a shortfall of 4,662 GWh by 2012 and 10,146 GWh by 2016[66]. If the needed electricity in 2012 is provided by a new baseload renewable project (such as a biomass project) with a 90% capacity factor, it is estimated that about 590 MW will be needed. However, if this requirement were met by an intermediary resource, such as a wind or hydroelectric project with a 32% summer peak availability factor, then a total of 1,663 MW of new wind (or hydroelectric) installed capacity would be needed. Section 5.11 discusses in detail the RPS targets of each state. The table below shows the cumulative renewable capacity in New England required to meet the RPS targets

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[63] ISO-NE, *2008 RSP*. October 18, 2008, pg 92.

[64] These two numbers include Vermont's Renewable Portfolio Goal's (RPG) of 25 % of energy demand coming from renewable units by 2020. Note that the RPG differs from the RPS in that it is not legally binding. However the RPG is currently set up so that if the original goals are not achieved by 2012 then a binding RPS will be passed in 2013.

[65] ISO-NE, *2008 RSP*. October 18, 2008, pg 92. Table 8-4, line 3 plus line 4

[66] ISO-NE, *2008 RSP*. October 18, 2008, pg 92.

during the forecasted horizon. Note that the modeling assumed, based on historical patterns, that some of the renewables would come from imports outside of the New England market; those imports are not included in the figure below.[67]

Figure 56. Cumulative renewable capacity needed to meet the RPS targets in New England under the Base Case

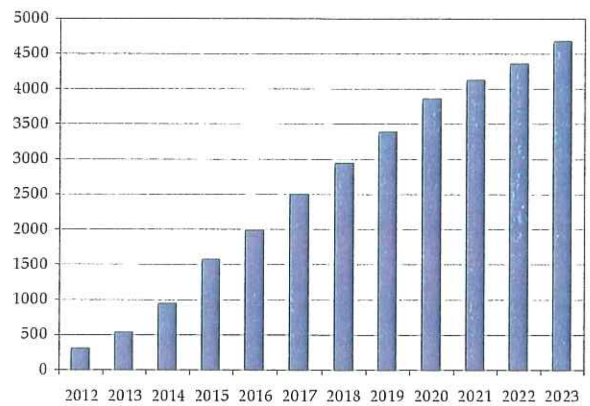
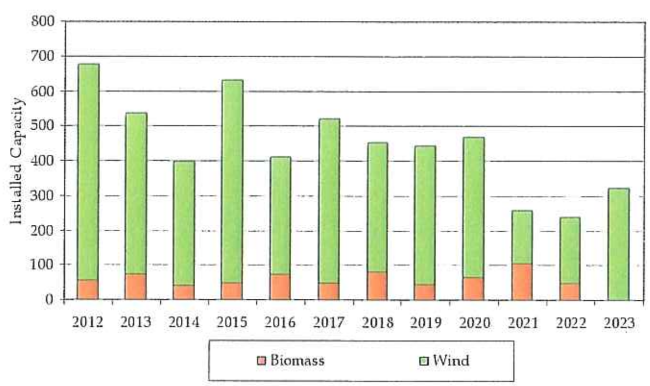


Figure 57. Modeled incremental new generic renewable capacity in New England (system-wide) from 2012-2023 under the Base Case (nameplate MW)



Source: LEI analysis based on the RPS targets in New England

Reliability requirements were the second criteria that guided the planning of generic new entry in the modeling. One of the most basic – yet most limiting - features of power supply and market operations is that supply must match demand in real time, and there must be enough generation resources to meet demand in the periods of greatest need and under conditions that put additional stress on the system, e.g. plant or transmission line outages. Thus, there is a need to have more capacity available to operate than would actually be dispatched under normal conditions. Hence, per Market Rules, the New England power system has to have total capacity installed at least equal to the Installed Capacity Requirement ("ICR"). The ICR is determined by the ISO and serves as the target procurement for in the Forward Capacity Market ("FCM"). In establishing the ICR, the ISO-NE determines the ICR level by using the probabilistic loss-of-load-expectation ("LOLE") analysis. [68] The analysis examines system resource adequacy under varying

[67] ISO-NE, *2008 RSP*. October 18, 2008, pg 97.

[68] ISO-NE, *2008 RSP*. October 18, 2008, p. 32.

assumptions for the load forecast, resource availability, and possible tie-line benefits (i.e., the receipt of emergency electric energy from neighboring regions). The amount of installed capacity (MW) the LOLE analysis assigns ensures that firm load is not disconnected more frequently than once in 10 years, which meet the Northeast Power Coordinating Council ("NPCC") and ISO resource adequacy planning criterion. To achieve the NPCC's "once-in-10-years" LOLE requirement, a bulk power system needs installed capacity equal to the expected demand plus a set reserve meant to handle any uncertainties in the generating system.

The figure below contains the ICR from 2010-2017 forecasts by ISO-NE and presented in the *2008 RSP*. Beyond 2017, the modeling assumed the continuation of 12% annual resulting reserve target (net of the HQ capacity credits) projected by the ISO-NE for the years 2010-2017. Thus, the forecasted representative future net ICR for 2017-2023 was derived by multiplying the forecasted 50/50 peak demands by 112%. The forecasted 50/50 peak demand for 2018-2023 were modeled according to historical growth trends, as will be discussed in Section 5.9.

I added generic capacity to meet projected ICR to simulated "balanced" condition in the capacity market.

Lastly, consistent with the market paradigm, a new entrant was assumed to enter into the market when expected market profits (i.e. sum of energy revenues, ancillary services payments and capacity market payments, and tax and REC incentives, where applicable) cover its all-in fixed costs (including its return on equity, debt charge, and fixed O&M). After the renewables quota is fulfilled, the remaining capacity additions were assumed to mainly come from CCGTs (or peakers, depending on economics), as these conventional resources are deemed to be the most likely entry candidates. These generic CCGTs are also likely to be the 'price setting resource' in the long run in both the energy and capacity markets.

Figure 58. Representative Future Net ICR, 2010-2023

Year	Forecast 50/50 Peak	Representative Future Net ICR	Annual Resulting Reserves
2010	28,955	32,305	12%
2011	29,405	32,528	11%
2012	29,820	33,209	11%
2013	30,190	33,702	12%
2014	30,510	34,084	12%
2015	30,790	34,437	12%
2016	31,035	34,781	12%
2017	31,250	35,058	12%
2018	31,438	35,211	12%
2019	31,603	35,395	12%
2020	31,746	35,556	12%
2021	31,872	35,697	12%
2022	31,982	35,820	12%
2023	32,077	35,927	12%

Source: Forecasted 50/50 Peak and Representative Future Net ICR for 2010-2017 from the 2008 RSP while the figures for 2018-2023 were derived from LEI's analysis based on historical trends (for the forecasted peak) and ISO-NE's projections on the annual resulting reserves.

Note: As defined in the 2008 RSP, the representative net ICR values above are "the representative Installed Capacity Requirements for the region, excluding the tie-reliability benefits associated with the Hydro-Quebec Phase I/II Interface."

5.4 Retirements

Certain announced retirements were also reflected in the model. Three plants in Connecticut were retired in 2013: the Bridgeport Harbor 2 (which has a summer capacity of 130.5 MW), Norwalk Harbor 1 and 2 (which have a summer capacity of 330 MW), and Montville 5. These plants currently have generator reliability agreements with ISO-NE, the need for which will cease to exist once future transmission projects- such as GSRP – are realized.[69] However, the modeling anticipated that the sites of these power plants will likely be employed for brownfield development down the road; therefore, generic new entrants in the longer term may be sited approximately in the same location as these mothballed facilities.

A plant was retired when profits are insufficient to cover its going forward fixed costs under rational investor behavior. Going forward fixed costs was the same as those used in developing the FCM bids by existing generators. In order to model this paradigm, each plant's profitability was analyzed periodically during the modeling timeframe. For each plant, combined revenues from all modeled markets were catalogued and these profits were compared to each plant's estimated going forward fixed costs to derive a plant's net profits.[70] If a plant had negative net profits for three consecutive years, it was retired. A three-year rule was used to reflect the observed inertia in deregulated markets across the US towards permanent plant closures, even in

[69] ISO-NE, *2007 RSP. October 18, 2007.* pg 95-96, Table 9-1

[70] In addition, the economics of environmental regulation were considered in the retirement analysis. Section 5.10 and 5.11 of this Appendix discuss in detail the environmental regulations in New England.

adverse market conditions. Although some developers have indicated in various venues that they may retire their capacity, such retirements are likely going to be coupled with repowerings on the same site. Such projects would need ISO-NE approval. This modeling did not incorporate such speculative retirements in our Base Case.[71]

I do not anticipate any hydroelectric or nuclear plant retirements in the modeling timeframe for the Base Case. However, two nuclear plants are facing license expiration in 2012 (685 MW of Pilgrim and 607 MW of Vermont Yankee). They have both applied to the U.S. Nuclear Regulatory Commission ("NRC") for an extension of their operating licenses in January 2006 and their individual applications are still under review.[72] While there has been some negative press for both nuclear facilities,[73] a panel of judges has dismissed questions regarding Pilgrim's radioactive leak monitoring system.[74] The modeling generally assumed that these plants do successfully get re-licensing approval and therefore not be retired. License renewals are not altogether unusual. For example, Millstone 2 and 3 had been in similar process (originally, their licenses expired in 2015) and had in 2005 successfully received their license extensions.

5.5 Plant operating parameters

POOLMod simulates the commitment and dispatch processes managed by the ISO-NE, and thus seeks to dispatch generation in the least cost manner to meet projected hourly load subject to transmission constraints. The modeling assumed that generators were bidding competitively and so their bids were derived from their marginal costs of operation, related to fuel costs and other variable costs. The fuel component of the cost of generation was derived from fuel prices and heat rates (thermal efficiency); variable costs include variable operations and maintenance costs ("VO&M") and emissions reduction costs (i.e., allowances). In this sense, the production cost of a given plant was determined by the corresponding fuel price, heat rate, VO&M costs, and emissions rates and allowance prices.

Heat rates, which were obtained from Ventyx, the Velocity Suite, are resource specific and are based, where available, on actual average heat rates, which take into account actual operating cycles and conditions. Ventyx, the Velocity Suite's process of obtaining the best average heat rate for a unit includes looking at the Environmental Protection Agency ("EPA") Continuous Emissions Monitoring Systems ("CEMS") data and performing a computational analysis of the heat input and unit output. When data is not available from the CEMS, Ventyx Velocity Suite either refers to the manufacturer's reported heat rate data, the EIA-860 (Annual Electric Generator Report), or conducts its own regression analysis based on the unit's technology, age, capacity, and fuel to determine a heat rate.

Similar to the heat rates, the VO&M costs are also plant specific. Ventyx, the Velocity Suites' VO&M cost estimates were used. These VO&M cost estimates were derived from cost data filed with the Federal Energy Regulatory Commission ("FERC") by generating facilities. These forms include the EIA Form 906, which is a collection of information from all regulated and

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[71] However, all resources were analyzed in our retirement module against their notional minimum going forward fixed costs, and therefore, some existing resources may be retired in the longer term if the economics so warrant.

[72] US Nuclear Regulatory Commission, Status of License Renewable Applications and Industry Activities, available online at http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html. Accessed on 21 October 2008.

[73] Audette, Bob, NRC responds to VY cracks. Brattleboro Reformer. November 13, 2008. Available at *http://www.reformer.com/ci_10974517?source=most_viewed*

[74] Knox, Robert. *Nuclear plant closer to winning 20-year license renewal. October 31, 2008. www.Boston.com.*

unregulated electric power plants and combined heat and power facilities in the US, and the FERC Form 1, which is an annual collection of operational and financial information reported by utilities and entities that are required to report to the FERC. In the modeling, the VO&M costs were indexed with time based on inflation.

The forced outage rates and maintenance assumptions data are also plant specific, based on each plant's prime mover type and size and cross-referenced with the NERC GADS database. Figure 59 below lists the indicative operating parameters that were used for modeling generation facilities in New England for the Base Case (note that the table aggregates by fuel type).

Figure 59. Indicative operating parameters for generation facilities

Fuel	Maintenance Week	Forced Outage Rate	Minimum Stable Generation	Minimum On/Off time
Coal	4	6.5%	33-39%	24 hours
Distillate	1	7.6%	44%	1 hour
Dual Fuel(Natural Gas-Residual)	4	8.5%	44%	1 hour
Dual Fuel(Natural Gas-Distillate)	2	7.2%	34%	1 hour
Dual Fuel(Residual-Distillate)	4	8.9%	50%	1 hour
Gas (Combined Cycle)	3	6.7%	35%	8 hours
Gas(Steam Units)	2	8.1%	42%	4hours
Gas (Gas Turbines)	4	7.7%	46%	1 hours
Methane Gas/Biomass/Etc.	4	8.1%	60%	4 hours
Nuclear	4	3.0%	85%	24 hours
Residual	4	10.3%	29%	1 hour
Wind	0	4.5%	0%	0 hours

Note: The Minimum Stable Generation ("MSG") of a plant is the lowest level of output at which it can be safely operated. When a plant is committed for use on a particular day, it must produce at least the MSG level of output at all times it is running.

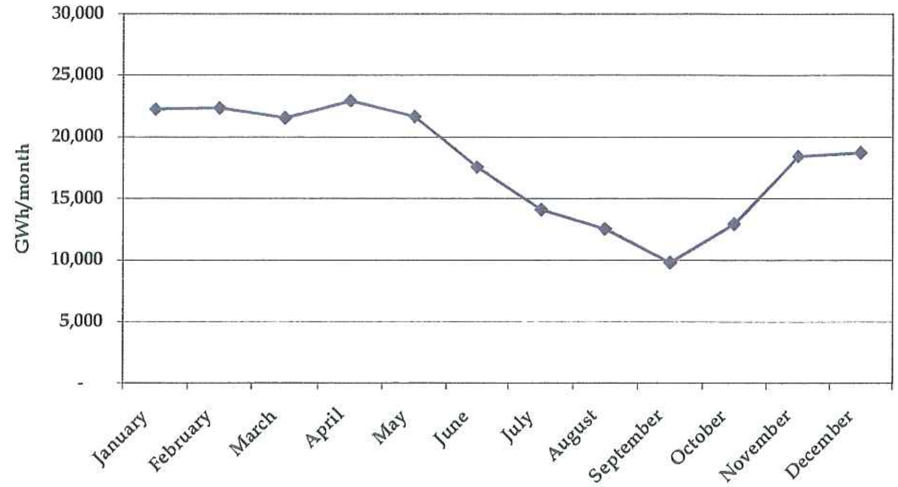
Sources: NERC, FERC; data collated through Ventyx, the Velocity Suite

5.6 Hydrology

Hydroelectric capacity in New England is not immaterial. In contrast to thermal generation, hydroelectric generation does not have a fixed marginal cost, which would be used to determine its position in the merit order. Rather, many hydroelectric generators are limited by daily, weekly or seasonal production profiles because of the source of the energy. POOLMod requires that a daily energy budget is projected by month and available maximum capacity by month which is then used to schedule the output of these resources into the daily merit order. Based on the scheduled position of the hydro resource and its flexibility to shift water to peak periods, the hydro shadow pricing algorithm then assigns a shadow price to the hydro resources, effectively denoting the opportunity cost of the energy it produces based on the marginal costs of the resource it displaced.

In order to determine the amount of energy schedules of the hydroelectric plants, the modeling relied on historical monthly production data for individual plants to create typical monthly energy budgets for each plant in our database. Run-of-river hydroelectric plants will produce more energy during high water availability months and less during the dry summer months, but specific generation levels in any given month may nevertheless vary from plant to plant. To determine the monthly energy budgets for each plant, the modeling considered their historical output over the past five years. Figure 60 shows the average monthly energy targets for all existing hydro in the system, as of 2008, based on a five-year average hydroelectric generation profile.[75]

Figure 60. Average monthly hydroelectric energy production for all existing New England hydroelectric plant



Source: Ventyx, the Velocity Suite

5.7 Demand response resources

In recent years, participation of demand resources in New England has increased. For example, demand response resources enrolled in the real-time programs have surged from 530 MW in January 2006 to 1,684 MW in January 2008.[76] The ISO-NE operates three reliability-activated demand response programs. These programs, which are considered capacity resources and as such are eligible to receive capacity transmission payments, include the Real-Time 30-Minute Demand Response Program, the Real-Time Two Hour Demand Response Program, and the Real-Time Profiled Response Program.

In our modeling, pre-existing (i.e., currently operating) demand response resources that have already qualified at ISO-NE for treatment as a capacity resource were included as resources in the supply stack. I also included new demand-side resources in recognition of the rising level of interest, as reflected in the recent FCAs. In the most recent FCA held in February 2009, there were over 2,900 MW of demand-side resources that cleared (or received capacity supply obligation)[77] and this result was also incorporated in our modeling. Given the operational concerns that ISO-NE raised in recent months, it is expected that only a portion of these new

[75] Note that I also looked at the 10-year average, but it was similar to the past 5 year average and as a result I will just use the five-year average weather normalized hydroelectric schedule.

[76] ISO-NE Independent Market Monitoring Unit, "*2007 Assessment of the Electricity Markets in New England,*" June 2008, pg 103.

[77] Among this total, 759 MW is derived from "Real Time Emergency Generation". In the Tariff Section III.13.7.2.5.2., the maximum amount of Real Time Emergency Generation allowed to be purchased in the auction is 600 MW. The result is an adjusted effective payment rate of $2.467/kW-month that will be multiplied by a Real Time Emergency Generation Resource's qualified capacity.

demand-side resources will remain in the market over the longer term, especially if capacity prices decline below levels at which demand-side resources are willing to curtail load. It is anticipated that only 40-60% of the new demand-side resources are able to remain permanently involved given the performance requirements and low levels of remuneration as compared to the opportunity costs of cutting load (the exception is emergency generation, which would not face the same opportunity costs). Overall, the modeling assumed that the total volume of demand-side resources would decline slowly from those levels that cleared in the FCA throughout the forecast period.

5.8 Fuel prices

Natural gas is the dominant fuel driver in the New England market. Gas-fired combined cycle gas turbines ("CCGTs") or simple cycle gas turbines ("SCGTs" or also referred to as peaking plants) set prices in these regions; hydro plants shadow price off of these gas-fired units. Oil-fired units also help to sustain high prices while coal and nuclear plants provide relatively low cost baseload power which is generally never price setting. According to ISO-NE's *2007 Annual Markets Report*, natural gas units or dual fuel fired units (with gas) were on the margin in nearly 75% of the pricing intervals.[78]

Fuel prices were developed based on current market trends. The fuel price projections used in this modeling were developed from various reliable input sources, such as forwards from NYMEX, long term fuel price forecasts produced by the US Department of Energy's Energy Information Agency ("EIA") 2008 Annual Energy Outlook, as well as historical data on delivered fuel costs to specific plants in New England. The base case gas price forecast was developed using the NYMEX forwards for the short and medium term, and then transitioned to long term fundamentals-based trends, such as the EIA's long-term forecast or historical commodity inflation indices, such as the Dow-Jones-AIG Commodity Index. For the past few years, the prices of oil and gas have been very volatile. Over the last twelve months, in fact, gas and oil prices have declined dramatically, attributable to the recent economic downturn. From a modeling perspective, these deviations should not affect the forecast of fuel prices in the longer term, as it is widely expected that the markets will revert to historical norms and long run average trajectories within three to four years, at about the start of our forecasted horizon.

Natural gas

Natural gas is generally priced with reference to the commodity price at Henry Hub, Louisiana plus an adder for transportation and local distribution charges. The primary gas pricing point in New England is the Boston Citygate. The historical five-year differentials of the Henry Hub prices and the Boston Citygate were examined. Based on the research, a five-year average of the pricing differential provides a reasonable proxy for the transportation basis adder. Although 2007 showed an upward trend, the start up of new offshore LNG terminals recently reduced some of the pressure on the gas pipeline networks and therefore should drive the basis down to the multi-year average of about 16%.

78 2007 Annual Energy Market, June 6, 2008, p. 42.

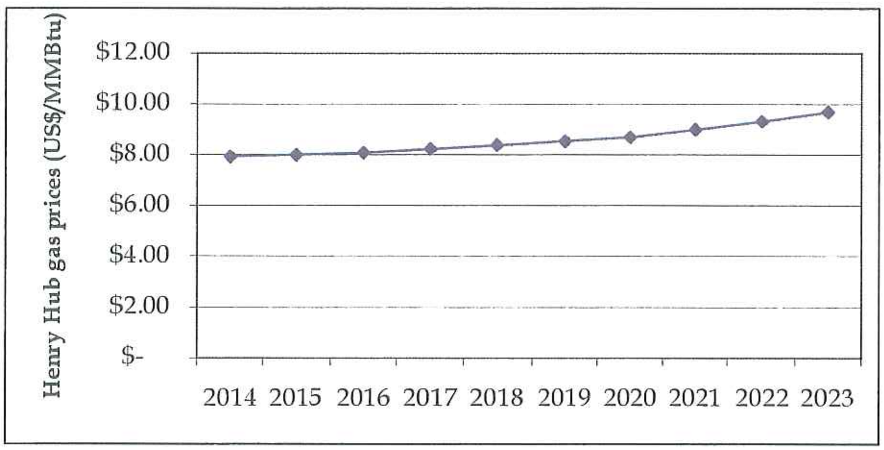
Figure 61. Five-year gas pricing differentials between Henry Hub and the Boston Citygate

Year	Gas Differential
2003	19.6%
2004	18.0%
2005	12.8%
2006	10.2%
2007	18.6%
5-Year Average	15.8%

Source: Bloomberg

The Base Case gas price forecast was developed by using NYMEX forward prices for the short and medium term, as of October 14, 2008 plus a transportation adder of 15.8%. For the long term, the modeling used an annual escalator of 3.5%, which represents the Dow-Jones-AIG Commodity Index natural gas historical growth trend from 1981 to 2006. This is slightly higher than pure economy-wide inflation, reflecting the greater upward price pressures on gas from oil markets and demand expansion from gas-fired generation. The projected Henry Hub natural gas commodity price is illustrated in Figure 62, while the projected delivered gas price to New England is shown in Figure 63.

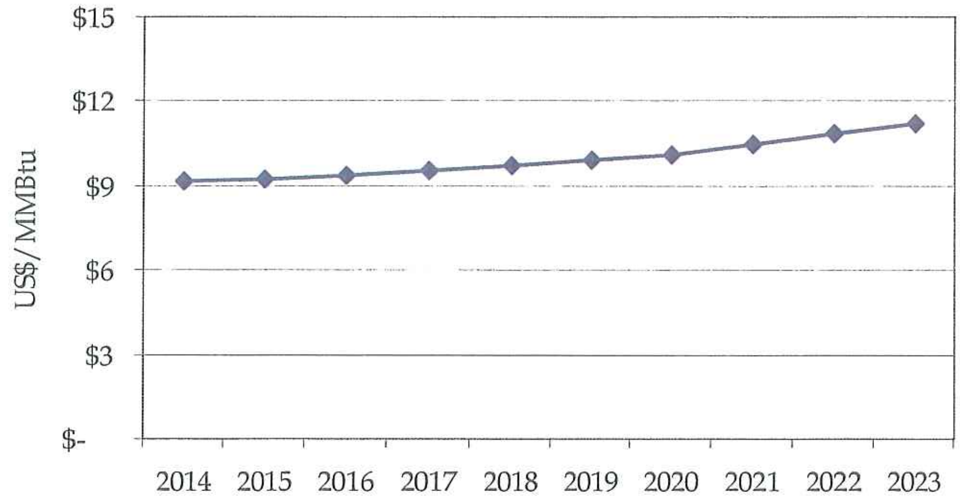
Figure 62. Projections of Henry Hub natural gas commodity prices under the Base Case (nominal$/MMBtu)



2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$ 7.90	$ 7.99	$ 8.10	$ 8.25	$ 8.41	$ 8.56	$ 8.72	$ 9.02	$ 9.34	$ 9.66

Source: Forecast developed with NYMEX futures. NYMEX futures downloaded from Bloomberg, accessed on October 14, 2008

Figure 63. Projected delivered gas prices under the Base Case (nominal $/MMBtu)

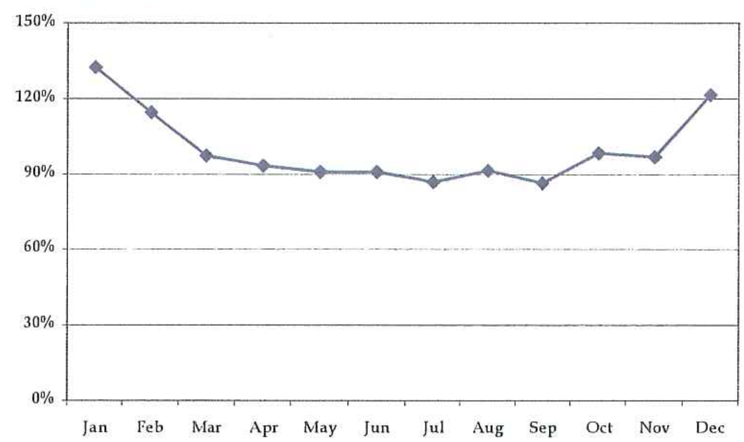


2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$ 9.1	$ 9.3	$ 9.4	$ 9.6	$ 9.7	$ 9.9	$ 10.1	$ 10.5	$ 10.8	$ 11.2

Note: The projected delivered gas price excludes the LDC charge. Given our research on delivered fuel costs by month and LDC rates, LEI believes that many gas-fired power plants in New England have contracts that bypass or discount out the LDC charges.

The Boston Citygate gas prices have also exhibited strong seasonal variations, as illustrated for a recent historical period in Figure 64. The historical seasonality pattern was used in the modeling.

Figure 64. Boston citygate gas price seasonality (2003-2007)



Source: LEI Analysis based on data from Bloomberg

Oil

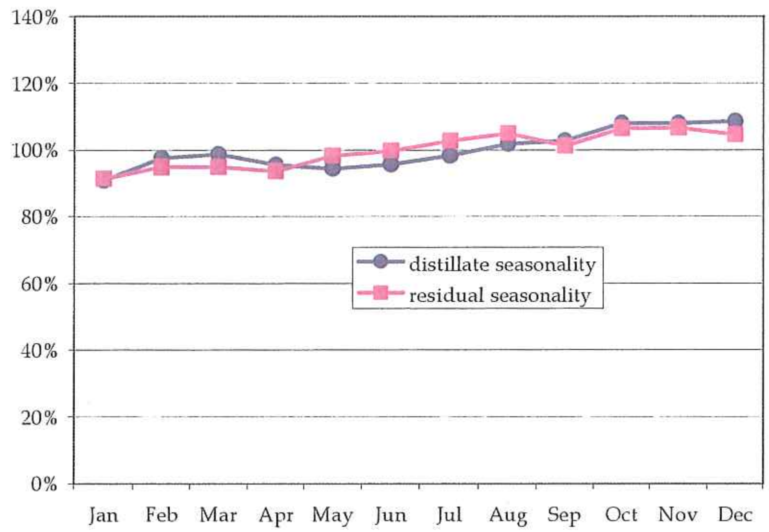
The starting point for distillate price was based on the heating oil forwards from NYMEX. The distillate-residual differentials were established from observed historical differentials between 2003 and 2007. Each fuel oil price track was then escalated based on the implied projected rate of growth for crude oil futures from NYMEX. For the period beyond the data availability of NYMEX market data, each fuel oil price track was extrapolated forward based on the implied projected rate of growth for crude oil futures from EIA's *Annual Energy Outlook* 2008. As a reference point the projected average crude oil futures price is US$84.19/barrel for 2009.[79]

Figure 65. Projected oil prices for New England under the Base Case (nominal $/MMbtu)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Residual	$ 12.5	$ 12.5	$ 12.5	$ 12.8	$ 13.2	$ 13.7	$ 14.2	$ 14.7	$ 15.3	$ 15.8
Distillate	$ 19.3	$ 19.3	$ 19.3	$ 19.8	$ 20.5	$ 21.2	$ 22.0	$ 22.8	$ 23.6	$ 24.4

Oil prices also present some level of seasonality, even though it is much weaker than the monthly seasonality for natural gas. Historical monthly New York Harbor distillate and residual prices between 2003 and 2007 were analyzed. Similar to natural gas seasonality, the five-year average oil seasonality profile was utilized in the forecast, as shown in the chart below.

Figure 66. Oil seasonality (2003-2007)



Source: LEI Analysis based on market data downloaded from Bloomberg

Coal

Given the diversity in coal sourcing, quality, and price, the modeling relied on plant specific coal price outlooks. The modeling began with an estimate of recent actual delivered costs reported in 2007, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels and different contracts for price and transportation), escalating it with the longer term trends for the commodity (the coal price index) and inflation rate from EIA's *Annual Energy Outlook 2008*. Therefore, each coal-fired plant has a specific and unique delivered fuel cost in the modeling, as summarized in the figure below.

[79] The 2009 projected crude oil price is based on the NYMEX Light Sweet Crude Oil futures, which was accessed on October 14, 2008.

Figure 67. Projected delivered coal prices under the Base Case (nominal $/MMBtu)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Coal For AES Thames	$ 2.9	$ 3.0	$ 3.0	$ 3.0	$ 3.1	$ 3.1	$ 3.1	$ 3.2	$ 3.3	$ 3.4	$ 3.4	$ 3.5
Coal For Brayton PT	$ 2.9	$ 2.9	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 3.1	$ 3.1	$ 3.2	$ 3.3	$ 3.3	$ 3.4
Coal For Bridgeport Station	$ 2.5	$ 2.5	$ 2.5	$ 2.5	$ 2.6	$ 2.6	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.9	$ 3.0
Coal For Bucksport Mill	$ 1.9	$ 1.9	$ 1.9	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.1	$ 2.1	$ 2.2	$ 2.2	$ 2.3
Coal For Mead Rumford Cogeneration	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.1
Coal For Merrimack	$ 3.3	$ 3.3	$ 3.3	$ 3.4	$ 3.4	$ 3.4	$ 3.5	$ 3.6	$ 3.7	$ 3.7	$ 3.8	$ 3.9
Coal For Mount Tom	$ 3.1	$ 3.1	$ 3.1	$ 3.2	$ 3.2	$ 3.2	$ 3.3	$ 3.4	$ 3.4	$ 3.5	$ 3.6	$ 3.7
Coal For S D Warren Westbrook	$ 3.1	$ 3.2	$ 3.2	$ 3.2	$ 3.3	$ 3.3	$ 3.4	$ 3.4	$ 3.5	$ 3.6	$ 3.7	$ 3.8
Coal For Salem Harbor	$ 2.7	$ 2.7	$ 2.7	$ 2.8	$ 2.8	$ 2.8	$ 2.9	$ 3.0	$ 3.0	$ 3.1	$ 3.2	$ 3.2
Coal For Schiller	$ 2.8	$ 2.8	$ 2.8	$ 2.8	$ 2.9	$ 2.9	$ 3.0	$ 3.0	$ 3.1	$ 3.2	$ 3.2	$ 3.3

5.9 Demand

Demand data used in the modeling consists of hourly load data for each zones for the duration of the analysis period. The sub-region hourly load profile from 2013 to 2017 was directly taken from ISO-NE's projected zonal hourly demand published in the CELT.[80,81] This is based on the ISO-NE 50/50 (or Reference Case) demand forecast. By definition, the 50/50 load forecast is an expected weather forecast – peak load under the 50/50 load forecast has a 50% chance of being exceeded. This is the most appropriate forecast to use in a long term modeling exercise, given the underlying logic for a long-term forecast. Thus, major assumptions and conditions – including weather – were assumed to approach or approximate the long run average.

In order to derive a forecast of hourly load after 2017, the growth rates in ISO-NE's forecasts and the relative acceleration (or deceleration) in the last two years were observed. Then those trends were used to extrapolate forward. In addition, no new electronic devices were assumed to go online during the forecasted period that would consume significant amount of load that would affect our demand projections.

Looking at the entire 10-year forecast period, it can be noted that most sub-regions are growing at around the same rate (around 0.3%-0.7% per annum for summer peak, slightly lower for energy), with the exception of New Hampshire whose peak demand is expected to grow by over 1.2% per annum, and its energy by 1.1% per annum.

[80] ISO-NE. CELT Forecasting data details. *See* http://www.iso-ne.com/trans/celt/fsct_detail/index.html

[81] The ISO-NE uses the operating companies' historical load data in conjunction with the FERC 715 seasonal peaks supplied by operating companies. A discussion of the ten year forecasts of the ISO-NE sub-areas can be found on this website: http://www.iso-ne.com/trans/celt/fsct_detail/2008/sub_area_forecast_2008_discussion.pdf

Figure 68. Projected peak demand and energy consumption for New England (Base Case)

ISO-NE	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Summer Peak	30,510	30,790	31,035	31,250	31,438	31,603	31,746	31,872	31,982	32,077
Growth rate	*1.1%*	*0.9%*	*0.8%*	*0.7%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*	*0.3%*	*0.3%*
Energy (GWh)	146,467	147,671	148,764	149,739	150,620	151,415	152,135	152,788	153,381	153,920
Growth rate	*0.9%*	*0.8%*	*0.7%*	*0.7%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*	*0.4%*
ME (ME + BHE)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	1,585	1,600	1,610	1,625	1,641	1,662	1,688	1,719	1,758	1,806
Growth rate	*1.3%*	*0.9%*	*0.6%*	*0.9%*	*1.0%*	*1.3%*	*1.5%*	*1.9%*	*2.3%*	*2.7%*
Energy (GWh)	9,156	9,239	9,308	9,375	9,436	9,493	9,545	9,593	9,637	9,678
Growth rate	*0.9%*	*0.9%*	*0.7%*	*0.7%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*	*0.5%*	*0.4%*
SME	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	705	710	715	720	725	730	735	740	745	750
Growth rate	*1.4%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*	*0.7%*
Energy (GWh)	3,716	3,750	3,783	3,799	3,811	3,819	3,824	3,827	3,829	3,830
Growth rate	*0.9%*	*0.9%*	*0.9%*	*0.4%*	*0.3%*	*0.2%*	*0.1%*	*0.1%*	*0.1%*	*0.0%*
NH	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	2,415	2,460	2,500	2,535	2,566	2,593	2,616	2,637	2,655	2,670
Growth rate	*1.9%*	*1.9%*	*1.6%*	*1.4%*	*1.2%*	*1.0%*	*0.9%*	*0.8%*	*0.7%*	*0.6%*
Energy (GWh)	11,547	11,729	11,909	12,068	12,217	12,351	12,476	12,589	12,692	12,787
Growth rate	*1.8%*	*1.6%*	*1.5%*	*1.3%*	*1.2%*	*1.1%*	*1.0%*	*0.9%*	*0.8%*	*0.7%*
CMA and NEMA	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	2,040	2,060	2,080	2,095	2,108	2,119	2,128	2,135	2,141	2,146
Growth rate	*1.0%*	*1.0%*	*1.0%*	*0.7%*	*0.6%*	*0.5%*	*0.4%*	*0.3%*	*0.3%*	*0.2%*
Energy (GWh)	9,608	9,695	9,768	9,836	9,895	9,948	9,995	10,037	10,075	10,108
Growth rate	*1.0%*	*0.9%*	*0.8%*	*0.7%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*	*0.3%*
BOSTON	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	5,925	5,960	5,990	6,010	6,025	6,036	6,044	6,050	6,054	6,057
Growth rate	*0.8%*	*0.6%*	*0.5%*	*0.3%*	*0.3%*	*0.2%*	*0.1%*	*0.1%*	*0.1%*	*0.1%*
Energy (GWh)	28,385	28,556	28,701	28,822	28,925	29,011	29,083	29,143	29,194	29,236
Growth rate	*0.7%*	*0.6%*	*0.5%*	*0.4%*	*0.4%*	*0.3%*	*0.2%*	*0.2%*	*0.2%*	*0.1%*
SEMARI (SEMA&RI)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	6,035	6,085	6,125	6,165	6,201	6,235	6,267	6,296	6,324	6,349
Growth rate	*0.9%*	*0.8%*	*0.7%*	*0.7%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*
Energy (GWh)	27,451	27,654	27,831	28,002	28,160	28,309	28,448	28,578	28,699	28,813
Growth rate	*0.8%*	*0.7%*	*0.6%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*
WMA&VT (WMA&VT)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	3,765	3,795	3,825	3,860	3,898	3,941	3,988	4,041	4,100	4,167
Growth rate	*1.1%*	*0.8%*	*0.8%*	*0.9%*	*1.0%*	*1.1%*	*1.2%*	*1.3%*	*1.5%*	*1.6%*
Energy (GWh)	19,751	19,891	20,026	20,145	20,255	20,355	20,447	20,529	20,605	20,674
Growth rate	*0.9%*	*0.7%*	*0.7%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*	*0.4%*	*0.3%*
CT	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	3,965	4,000	4,035	4,060	4,081	4,098	4,112	4,123	4,132	4,139
Growth rate	*1.1%*	*0.9%*	*0.9%*	*0.6%*	*0.5%*	*0.4%*	*0.3%*	*0.3%*	*0.2%*	*0.2%*
Energy (GWh)	18,042	18,181	18,306	18,424	18,533	18,635	18,729	18,817	18,899	18,975
Growth rate	*0.9%*	*0.8%*	*0.7%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*	*0.5%*	*0.4%*	*0.4%*
SWCT	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	2,655	2,685	2,705	2,725	2,742	2,757	2,770	2,782	2,792	2,802
Growth rate	*1.0%*	*1.1%*	*0.7%*	*0.7%*	*0.6%*	*0.6%*	*0.5%*	*0.4%*	*0.4%*	*0.3%*
Energy (GWh)	12,398	12,513	12,619	12,716	12,805	12,886	12,961	13,029	13,091	13,149
Growth rate	*1.1%*	*0.9%*	*0.8%*	*0.8%*	*0.7%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*	*0.4%*
NOR	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Summer Peak	1,425	1,435	1,450	1,460	1,471	1,480	1,490	1,498	1,506	1,514
Growth rate	*1.1%*	*0.7%*	*1.0%*	*0.7%*	*0.7%*	*0.6%*	*0.6%*	*0.6%*	*0.5%*	*0.5%*

Note: 2014-2017 data (in black) is from 2008 ISO-NE CELT; 2018-2023 (in blue) were modeled according to historical growth trends (based on the previous 2 years).

5.10 Emissions costs

Emissions generated by electricity generators include Carbon Dioxide (CO_2), Nitrogen Oxide compounds (NOx), and Sulfur Dioxide (SO_2). Among them, NOx and SO_2 are the two most important factors causing acid rain and air pollution, and thus are the two emissions for which generators are currently regulated. The Clean Air Act ("CAA") requires each state to develop State Implementation Plans that contain control measures and strategies used to attain and maintain the national air quality standards within their borders. I modeled existing regulations based on our state-level research. The Base Case did not include the implications of Clean Air Interstate Rule ("CAIR") because the courts have recently remanded it and therefore there is currently no compliance requirement for the tighter emissions limits underpinning CAIR.[82] The process for incorporating environmental regulations is described in the section below.

Sulfur dioxide and nitrogen oxide

SO_2 is primarily generated by coal-fired units due to the high sulfur content of coal while NOx exists in the emissions of all fossil fuel-fired plants. Acid Rain and Ozone Transport Commission ("OTC") are the two major US Federal level regulations that cap the SO_2 and NO_x emission in the Northeast states. For the coal units, the cost of compliance through allowance purchases is not prohibitive, given the strong margins earned by these plants in New England. In addition, many coal-fired plants have already switched to coal with lower sulfur contents, and many have installed devices to curtail emissions of both SO_2 and NOx.

Figure 69. Emission technology of selected coal and oil-fired generating plants in New England

Plant Name	Primary Fuel Code	Nameplate Capacity MW	SO_2 Control Equipment	NOx Control Equipment
AES Thames	Coal	214	Fluidized Bed Limestone Injection	Other
Brayton PT	Coal	241	Dry Lime FGD	Low NOx Burner Technology with Closed-coupled Separated OFA; Selective Catalytic Reduction
Brayton PT	Coal	643		Low NOx Burner Technology with Overfire Air; Selective Catalytic Reduction
Mystic	Residual Fuel Oil	617		Low NOx Burners
Canal Plant	Residual Fuel Oil	585		Low NOx Burner Technology with Overfire Air; Other; Selective Catalytic Reduction
Norwalk Harbor 1 & 2	Residual Fuel Oil	326		Selective Non-catalytic Reduction
Bridgeport Harbor 2 & 3	Residual Fuel Oil/Coal	563		Low NOx Burner Technology with Separated OFA

Source: Ventyx the Velocity Suite, accessed on October 27, 2008

The first step in incorporating the environmental regulation is examining the thermal plant's reported historical emission rates. For SO_2 and NOx, when a plant's emission rates exceed the state-specific environmental emission compliance limits, a plant owner can either choose to install pollution abatement equipment or purchase emission allowances. A decision is made depending on which approach costs less on a present value basis. Hypothetically, when a plant owner chooses to install pollution abatement equipment, capital costs (amortized over 5 years) are added to its going forward fixed costs. And these capital costs effectively increase the fixed going

[82] On July 11, 2008, the D.C. Circuit vacated the Energy Protection Agency's CAIR. The ruling is available online at http://www.epa.gov/cair/pdfs/05-1244-1127017.pdf

forward costs for covered plants. On the other hand, if a plant owner chooses to purchase emission allowances, allowance costs are added to the variable costs. Using emission rates (lbs/MMBtu) net of the emission limits for SO_2 and NOx individually for each plant, the allowance purchase costs can be estimated using this net emissions rate, plant specific heat rate and the current outlook for allowance prices.

The calculation of emission costs was based on current emissions limits (i.e., 0.3 lbs/MMbtu of SO_2 and 0.15 lbs/MMbtu of NOx) and an analysis of typical emissions levels by plant (using historical generation (MWh), heat rates (MMBtu/MWh), and recorded volumes of emissions (lbs of SO_2 and NOx) of those plants). This information allowed the calculation of the corresponding emission rates (lbs/MMBtu) net of the emission limits for SO_2 and NOx individually for each plant. Assuming grandfathered allowance allocations, a power plant would need to buy allowances for the extra emissions they produce above the limit or install abatement equipment to lower emissions. In most instances, cost effective pollution controls have been installed already. Therefore, the optimal compliance strategy is to purchase allowances. The allowance purchase costs were estimated using this net emissions rate and the current outlook for allowance prices (\$204.5/ton for SO_2 and \$665/ton for NOx).[83] The figure below shows an example of how SO_2 allowance costs are calculated for this analysis.

Figure 70. Example of SO_2 allowance cost calculation

Unit	Total heat input (MMBtu)	Total generation (MWh)	SO2 emissions (Tons)	SO2 emissions (lbs)	SO2 Emission rate (lbs/mmbtu)	Excess SO2 emissions (lbs/mmbtu)	SO2 emission cost adder (US$/MMBtu)	Heat Rate (Btu/kWh)	SO2 Emission Cost Adder ($/MWh)
Merrimack 1	10,869,518	954,502	11,420	25,153,730	2.31	2	$0.14	10,572	$1.53
Salem Harbor 1	5,961,880	540,030	1,931	4,254,069	0.71	0.4	$0.03	10,277	$0.31

Source: Heat input, generation and emissions levels generated from Ventyx, the Velocity Suite

Note: Estimated SO_2 emission allowance used is \$143.6/ton (for 2014), which is based on the NYMEX Green Exchange as of October 24th, 2008; NOx allowance costs are calculated in the same manner.

While allowance prices of SO_2 and NO_x are available from various sources, the modeling relied on the NYMEX Green Exchange for the forward SO_2 and NO_x allowance prices. For the period beyond the forwards, it is assumed that allowance prices escalate with commodity gas price trends, given that gas-fired generation represent the 'low emitting' alternative and is price setting in most hours, therefore serving as a limiting benchmark for how much additional costs prices will absorb.

[83] The allowance prices of SO2 and NOx for 2009 are obtained from NYMEX Green Futures, October 24, 2008.

Figure 71. Allowance prices ($ per ton) by pollutant (NOx and SO_2)

Year	NOx Seasonal Emission Allowance	SO_2 Emission Allowance
2014	$ 753.5	$ 143.6
2015	$ 762.3	$ 148.2
2016	$ 772.8	$ 150.2
2017	$ 787.1	$ 153.0
2018	$ 802.4	$ 156.0
2019	$ 817.2	$ 158.8
2020	$ 831.8	$ 161.7
2021	$ 861.0	$ 167.3
2022	$ 891.1	$ 173.2
2023	$ 922.3	$ 179.3

Sources: LEI analysis based on the data from the NYMEX Green Exchange

Carbon dioxide

Concerns about global warming have catalyzed proposals for carbon emissions limits worldwide, which would affect the transportation sector as well as the energy sector, since the burning of fossil fuels (coal, gas, and oil) emits carbon dioxide. The Kyoto Protocol, a protocol to the international framework convention on climate change, represents the largest international effort to date aimed at reducing greenhouse gases that cause climate change. Though the US has not ratified the Kyoto Protocol, there are ongoing legislative discussions in the Senate and at Congress regarding national climate change legislation. Some states have instituted state legislation. And in New England, a regional cap-and-trade program, the Regional Greenhouse Gas Initiative ("RGGI"), has been ratified by the states and implemented.

The RGGI is a regional cap-and-trade program that aims to reduce greenhouse gas ("GHG") emissions (including CO_2) from power plants in the northeastern states of the US. With an implementation date of January 1, 2009, and ten participating states[84] as of today (including all six New England states), it is one of the largest carbon programs in the US. The number of participating states may increase in the future, as well as the sources of greenhouse gas ("GHG") emissions and types of GHGs other than CO_2. The regional auction design is currently under development. Each state can also establish local auctions for its state only.

The RGGI cap on CO_2 emissions from power plants greater than 25 MW took effect in the Northeast states, including those in New England, beginning in January 2009. The RGGI target (cap) has two phases: the regional cap of 188 million short tons from 2009 to 2014; and a 10% reduction from 2015 to 2018 (2.5% per year). The initial cap is approximately 4% above the annual average emissions, based on the data from 2000 to 2004. Therefore, the first phase is mainly to sustain the current level, and the reduction obligation comes in after 2015. The program has a compliance period of three years, meaning that generators have three years to trade

84 Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont

allowances and to meet each year's goal. The states must allocate 25% of allowances to support consumer benefit programs. Consumer benefit programs would aim "to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon emitting energy technologies, and to stimulate or reward investment in the development of innovative carbon emissions abatement technologies."[85] Although the remaining 75% can be allocated freely by each state, most of the states indicated their intention to auction 100% or nearly 100% of the allowances to fund the consumer benefit programs. Those states include New York, Massachusetts, Vermont, Rhode Island, Connecticut, and Maine.[86] Penalties for the excess emissions over the cap will be determined and imposed by each state. There have been four RGGI auctions so far and the prices were cleared at $3/ton to$3.5/ton level[87] for 2009 vintage allowances, the market still expects higher prices by the time we reach compliance deadlines. Currently, there is no federal carbon legislation in the United States. However, many industry participants and observers expect to see one implemented very soon. A national program is likely to create upward pressure on the cost of carbon allowances.

In the Base Case modeling, it was assumed that states will auction 100% of the allowance and all plants will be required to be 100% carbon neutral. Each plant will be required to purchase an allowance to offset every ton of CO_2 it emits. It was further anticipated that plant owners would start complying with CO_2 allowance prices starting at about $15/ton. Similar to the SO_2 and NOx, it is expected that CO_2 allowance prices will escalate with the projected gas price trends. The table below shows CO_2 allowance prices for the modeling horizon. LEI's CO_2 allowance price forecast is generally consistent with range of assumptions made by ISO-NE in its various economic analyses. In ISO-NE's Electricity Scenario Analysis study conducted in 2007, it assumed $20/ton as the baseline CO_2 cost, but also does sensitivities using $3/ton and $40/ton.[88] In addition, the ISO-NE assumed that CO2 costs $10/ton in its economic analyses on the Maine Power Connector, which was presented last May 2008.[89]

Figure 72. CO_2 allowance price projections for the Base Case (nominal $/ton)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$ 15.0	$ 15.2	$ 15.4	$ 15.7	$ 16.0	$ 16.3	$ 16.6	$ 17.1	$ 17.7	$ 18.4

5.11 Renewable portfolio standard regulations

In New England, the RPS is generally based on a pre-determined percentage of the states' total output sold or generated. Figure 73 and Figure 74 below show the current RPS requirements by state. Note that Vermont has a Renewable Portfolio Goal ("RPG"), which unlike the RPS in other states is not legally binding. However the state goals will be reviewed in 2012, if the goals are not met then they will be changed to a binding RPS.

[85] RGGI, http://www.rggi.org/docs/program_summary_10_07.pdf

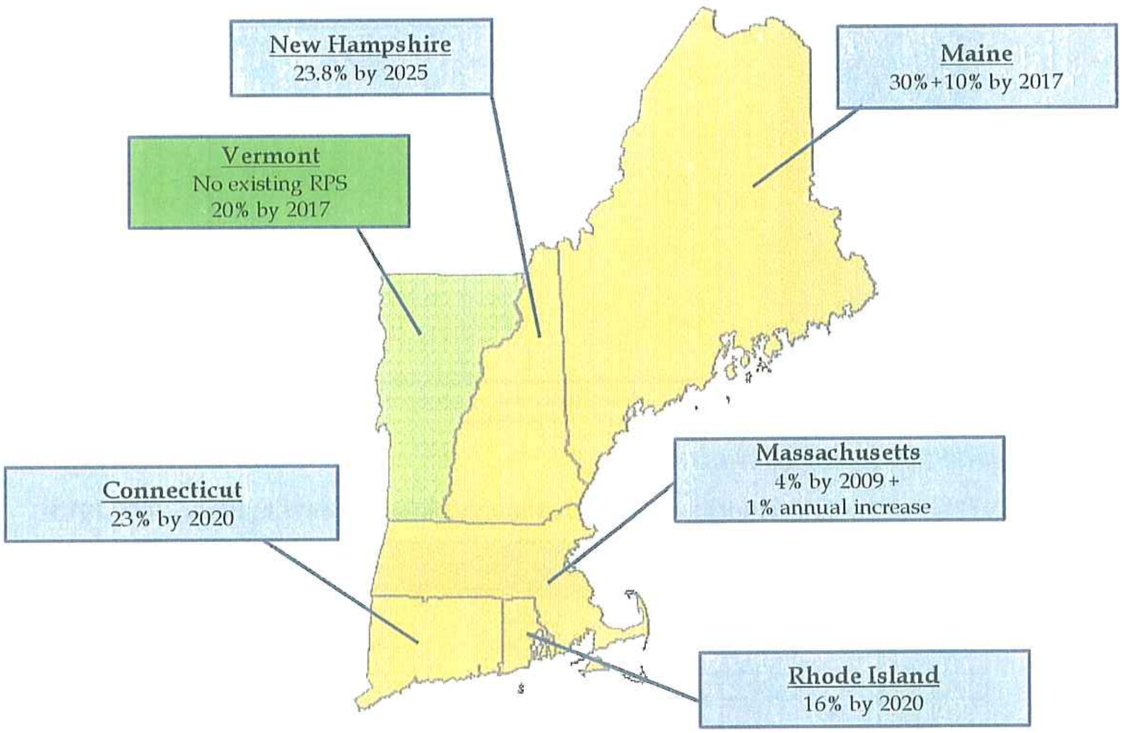
[86] Ibid.

[87] RGGI Inc., http://www.rggi.org/co2-auctions/results

[88] ISO-NE. *"New England Electricity Scenario Analysis,"* August 2, 2007, pg. 29.

[89] ISO-NE Economic Studies Working Group, *"Maine Power Connector Economic Analyses,"* Presentation of the Mr. Wayne Coste on the May 22, 2008. Slide 17.

Figure 73. Summary of RPS requirements in New England, by state



Note: Connecticut's targets for Class I renewables are 20% by 2020 plus an additional 3% coming from class II renewables
Source: US Database of State Incentives for Renewables and Efficiency (DSIRE), April 2008.

Figure 74 and Figure 75 below illustrate the eligible technologies under RPS, along with the percentage requirements for the five New England states (Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island) under RPS mandates (Vermont currently has implemented only a voluntary RPS program as noted above). The second table lists the annual percentage of electricity consumption that renewable technologies must supply the system until 2018. ISO-NE considers Massachusetts, Rhode Island, Connecticut Class I and New Hampshire's Class I and II requirements to be the main drivers for new renewable resources growth in the region.[90]

[90] ISO-NE, *2007 RSP. October 18, 2007*, p. 89.

Figure 74. Eligible technologies under state RPS requirements in New England[91]

Technology	CT			MA	ME	NH				RI
	I	II	III			I	II	III	IV	
Solar Thermal	●			●	●	✪	✪			●
Photovoltaics	●			●	●	✪	✪			●
Ocean Thermal	●			●		✪				●
Wave	●			●		✪				●
Tidal	●			●	●	✪				●
Wind	●			●	●	✪				●
Biomass	①	●		②	●	✪		⑥		●
Hydro	✪ ⑤	⑤			●	✪			⑤	⑦
Landfill Gas	●			●	●	✪		●		●
Anaerobic digestor				●		✪		●		●
Fuel Cells	●			③	●					③
Geothermal					●	✪				●
Municipal Solid Waste		●			④					
Combined Heat and Power			✪		●					
Energy Efficiency			✪							

Notes: ✪ *new or recent (past five years) technology; (1) sustainable, low emission; (2) low-emission, advanced technology; (3) with renewable fuels; (4) with recycling; (5) less than 5 MW; (6) less than 25 MW; (7) less than 30 MW.*

Source: ISO-NE, *2007 RSP. October 18, 2007*. p. 87

Figure 75. RPS percentage requirements by technology class in New England, 2007-2018

Year	CT			MA[1]	ME		RI		NH			
	I	II	III	I[a]	Existing	New	Existing	New	I	II	III	IV
2008	5.0		2.0	3.5		1.0		1.5	0.0	0.0	3.5	0.5
2009	6.0		3.0	4.0		2.0		2.0	0.5	0.0	4.5	1.0
2010	7.0		4.0	5.0		3.0		2.5	1.0	0.0	5.5	1.0
2011	8.0		4.0	6.0		4.0		3.5	2.0	0.1	6.5	1.0
2012	9.0		4.0	7.0		5.0		4.5	3.0	0.2	6.5	1.0
2013	10.0		4.0	8.0		6.0		5.5	4.0	0.2	6.5	1.0
2014	11.0		4.0	9.0		8.0		6.5	5.0	0.3	6.5	1.0
2015	12.5	3 % in all year	4.0	10.0	30 % in all year	8.0	3 % in all year	8.0	6.0	0.3	6.5	1.0
2016	14.0		4.0	11.0		9.0		9.5	7.0	0.3	6.5	1.0
2017	15.5		4.0	12.0		10.0		11.0	8.0	0.3	6.5	1.0
2018	17.0		4.0	13.0		10.0		12.5	9.0	0.3	6.5	1.0
2019	19.5		4.0	14.0		10.0		14.0	10.0	0.3	6.5	1.0
2020	20.0		4.0	15.0		10.0		14.0	11.0	0.3	6.5	1.0
2021	20.0		4.0	16.0		10.0		14.0	12.0	0.3	6.5	1.0
2022	20.0		4.0	17.0		10.0		14.0	13.0	0.3	6.5	1.0
2023	20.0		4.0	18.0		10.0		14.0	14.0	0.3	6.5	1.0
2024	20.0		4.0	19.0		10.0		14.0	15.0	0.3	6.5	1.0

Note: Columns labled "New" represent RPS Standard on New Generation
[a] Installed after 1/1/1997

[1] Massachusetts is in the process of defining a Class I and II under the Green Communities Act of 2008. The new definitions are said to be put in place by January 1, 2009.

Source: ISO-NE, *2007 RSP. October 18, 2007* p. 88; *US DSIRE accessed on October 2008*

5.12 Capacity market assumptions

The LEI modeling replicates the auction process embedded in the FCA, through a simulation of expected supply-demand conditions. As stated earlier, bidding in the FCM is based on the general principles of competition, economically rational behavior and perfect foresight/information. Recognizing that a competitive market dynamic are modeled, the FCM bid is essentially truing up

91 Massachusetts is in the midst of changing the previous RPS requirements, as its revised RPS was announced in January 2009, http://www.mass.gov/?pageID=eoeeapressrelease&L=1&L0=Home&sid=Eoeea&b=pressrelease&f=090106_pr_rps_regs&csid=Eoeea

existing generators' profits so that they remain economically viable and avoid retirement. On the other hand, for new entrants, the FCM bid represents the realization of the expectation that new generators will earn sufficient revenues from the combined ISO markets to cover their all-in fixed costs and therefore serves as the impetus to enter the market. In the FCM modeling, the competitive bidding is therefore formulated according to the following rules:

Bids for existing unit	=	Minimum Going-forward fixed costs	-	Expected (energy profit)	-	Expected (LFRM profit)
Bids for new unit	=	All-in fixed costs	-	Expected (energy profit)	-	Expected (LFRM profit)

Despite the forward nature of the FCA, the modeling assumes that there is perfect information knowledge and that generators can accurately predict their future energy revenues - hence their expected energy profits actually being their realized energy profits in the modeling.

Minimum going forward fixed costs

For the minimum going-forward fixed costs, fixed O&M costs as well as a market estimate of debt payments were included. Fixed O&M data was obtained from Ventyx, the Velocity Suite.[92] Figure 76 below documents the assumptions used in the fixed O&M costs by technology type. In our modeling, these nominal fixed O&M costs are escalated at 2% p.a., a long term inflation rate assumed in EIA's 2008 *Annual Energy Outlook.*[93]

Figure 76. Fixed O&M costs by generator type (in 2009 $/kW-year)

Type	$/kW/year	
Bituminous Coal	$	31.1
Distillate Fuel Oil	$	25.9
Landfill Gas	$	78.2
Municipal Solid Waste	$	26.1
Natural Gas	$	21.0
Biomass Gases	$	30.7
Residual Fuel Oil	$	15.7
Subbituminous Coal	$	26.1
Uranium	$	86.6
Water	$	18.2
Wood	$	21.7
Wood Waste Solids	$	26.5
Wind	$	31.4

Source: Ventyx, the Velocity Suite

[92] Ventyx, the Velocity Suite estimates fixed O&M costs using data from the EIA 906 forms and the FERC Form 1. In addition, the generator capacity information required to estimate fixed costs are derived from EIA 860 existing and planned generator data, NERC ES&D 411, EIA 906, as well as original research conducted by the predecessor to Ventyx, Global Energy Intelligence. FERC Form 1 does not require filers to state the fixed and variable components of operations and maintenance costs. Global Energy Intelligence developed a method that uses the 80/20 rule (80 refers to the percentage of operation and maintenance costs that can be attributed to fixed costs and the 20 refers to the percentage of operation and maintenance costs that can be attributed to variable costs) as a loose guideline, but is then informed by an analysis of capacity factor and production cost data, which Global Energy Intelligence refers to as "the capacity factor cost estimation method" or CFCE Method.

[93] EIA Annual Energy Outlook 2008, Table 19.

In addition, generic technology-based estimates of the debt component was developed by assuming refinancing of debt to implied market values and 60% leverage across all technology types, with twenty-year amortization period for the debt, and an annual interest rate ranging from 7% to 8.5% depending on the technology. Debt should be included in the minimum going forward fixed costs because developers are treating it as 'avoidable' in case of closure (as evidenced by distressed asset transfers to banks in instances where it was more economic for the developer to walk away).

The table below shows the minimum going forward fixed costs for existing capacity by fuel type. The operating cost assumptions (fixed operating and maintenance costs) were inflated with 2% per annum, following the assumed inflation rate from the 2008 *Annual Energy Outlook.*[94] Indirectly, minimum going forward fixed also serve to signal the need for retirements.

Figure 77. Sample calculation of total minimum going-forward fixed costs for existing plants ($/kW-year)

Fuel	Mover	Market Values ($/kW)	Intrest Rate (annual)	Leverage	finance term (years)	Annual Mortgage ($/kW-year)	FOM ($/kW-year)	Going Forward Fixed Cost ($/kW-year)	Going Forward Fixed Cost ($/kW-month)
Uranium	Nuclear Reactor	$ 900.00	7.0%	60%	20	$ 51.00	$ 86.60	$ 137.60	$ 11.46
Coal	Steam Turbine	$ 600.00	7.5%	60%	20	$ 35.30	$ 31.10	$ 66.40	$ 5.53
Natural Gas	CC	$ 650.00	8.5%	60%	20	$ 48.60	$ 21.00	$ 81.49	$ 6.79
Natural Gas	Steam Turbine	$ 500.00	8.0%	60%	20	$ 30.60	$ 21.00	$ 51.60	$ 4.30
Natural Gas	GT/IC	$ 300.00	8.5%	60%	20	$ 19.00	$ 21.00	$ 40.00	$ 4.34
Distillate Fuel Oil		$ 250.00	8.0%	60%	20	$ 15.30	$ 25.90	$ 41.20	$ 3.43
Residual Fuel Oil		$ 250.00	8.0%	60%	20	$ 15.30	$ 15.70	$ 31.00	$ 2.58
Wind	Wind Turbine	$ 300.00	8.5%	60%	20	$ 19.00	$ 31.40	$ 152.80	$ 12.73
Biomass/ Landfill Gas/ Wood waste		$ 250.00	8.5%	60%	20	$ 15.90	$ 54.10	$ 127.26	$ 10.61
Hydro		$ 800.00	8.5%	60%	20	$ 50.70	$ 18.20	$ 68.90	$ 5.74

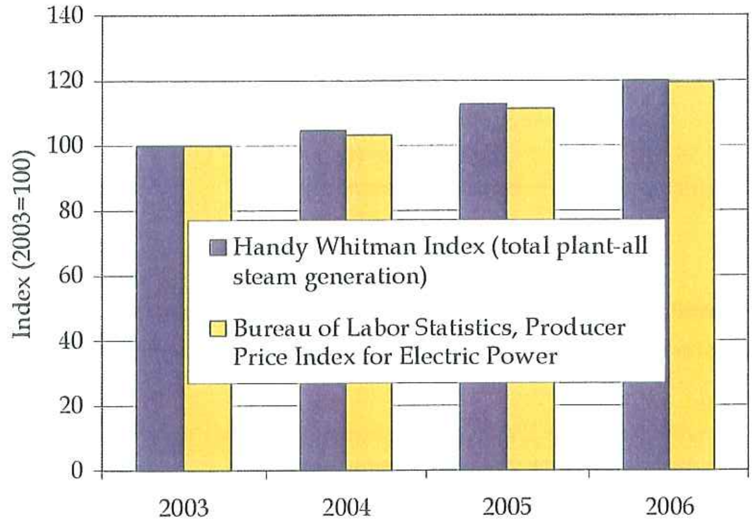
All-in Fixed Costs

In contrast, new capacity's all-in fixed cost covers not only debt services and fixed operating and maintenance costs, but also return on equity. A new entrant is assumed to 'bid' this entire amount into the FCA, less its expected energy and LFRM profits, in its first year of operation.

Capital costs are a primary component of all-in levelized costs and are the basis for estimating the cost of capital components listed above. Capital costs are practically one of the most difficult to ascertain, as developers are generally reticent about disclosing their project's investment value. Moreover, capital costs have been rising significantly recently. The Handy Whitman Index, reflecting the global nature of construction equipment and raw materials markets, has shown an almost 20% increase for the electric generation sector cost index between 2003 and 2006. The Producer Price Index ("PPI") for Electric Power from the Bureau of Labor Statistics ("BLS") also shows the same rising trend. Based on the January 2006 to September 2008 BLS PPI for Electric Power, it can be seen that there was an additional 10% increase in costs since 2006.

[94] Ibid.

Figure 78. Selected cost index for the energy sector



EIA publishes capital costs assumptions for various technologies. However, the assumptions are on the low end and do not reflect this recent trend. Recent announced capital cost estimated by developers and capital cost assumptions published by ISO-NE[95], and actual capital costs and financing of projects constructed in the last ten years in the Northeast were surveyed to derive the assumed capital costs. Given observed trends in costs, I have assumed that the nominal capital is \$1,000/kW for CCGT and \$2,000/kW for wind in 2009 in our Base Case. The tables below list the all-in fixed cost assumptions for generic CCGT and on-shore wind projects in New England (under our Base Case).

Figure 79. All-in fixed cost assumptions for CCGT

analysis year	2014	2019	2023
leverage		60%	
debt interest rate		8.5%	
after-tax required equity return		16.0%	
corporate income tax rate		40%	
debt financing term		20 years	
equity contribution capital recovery term		20 years	
construction time		36 months	
nominal capital cost, \$/kW	\$ 960	\$ 1,039	\$ 1,125
nominal fixed O&M, \$/kW/year	\$ 22.7	\$ 25.1	\$ 27.1

95 ISO-NE PAC meeting material, "Update on Generation Generic Capital Costs", January 21st 2009, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/a_capital_costs.pdf

Figure 80. All-in fixed cost assumptions for wind

analysis year	2014	2019	2023
leverage		60%	
debt interest rate		8.5%	
after-tax required equity return		16.0%	
corporate income tax rate		40%	
debt financing term		10 years	
equity contribution capital recovery term		10 years	
construction time		20 months	
nominal capital cost, $/kW	$ 2,164	$ 2,341	$ 2,534
nominal fixed O&M, $/kW/year	$ 34.0	$ 37.5	$ 40.6

To derive the estimates above, the following assumptions over the modeling timeframe are incorporated:

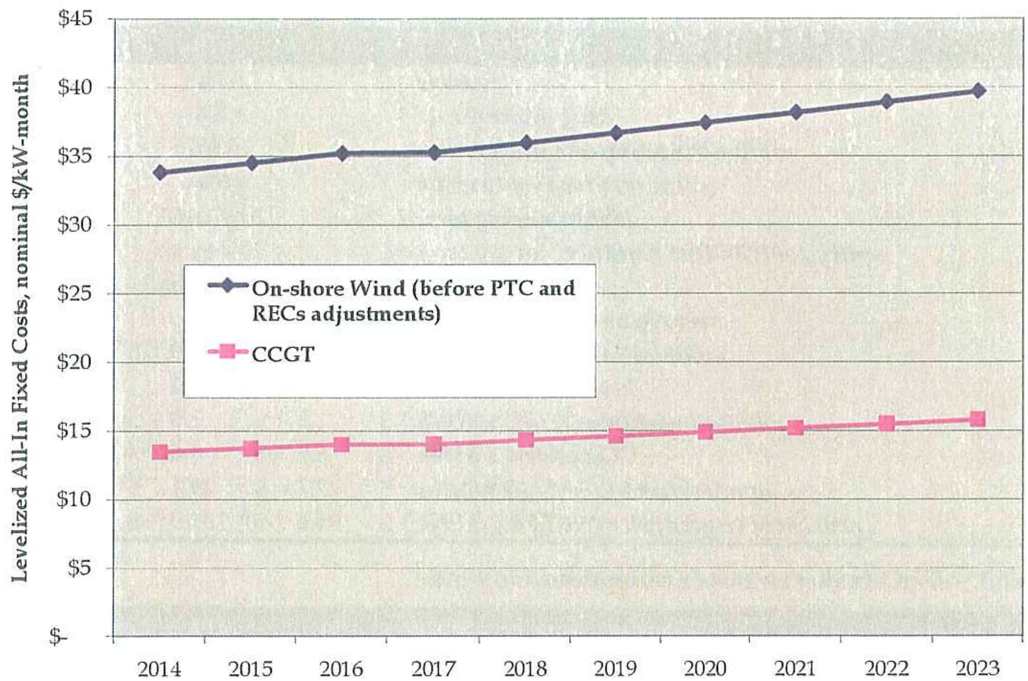
- Capital cost is inflated at 2% p.a., per the assumed inflation rate from the Energy Information Administration's *Annual Energy Outlook.*[96]
- Operating cost assumptions (fixed and variable operating and maintenance costs) are also inflated at 2% p.a., per the *Annual Energy Outlook.*[97]
- Technological improvements are assumed that heat rates decrease by 2% every 3 years and capital costs decrease by 2% every 4 years.

Given these assumptions, the all-in fixed costs for generic CCGT and wind generators are developed and shown in the figures below.

[96] EIA *Annual Energy Outlook* 2008, Table 19.

[97] Ibid.

Figure 81. Levelized all-in fixed cost for CCGT and wind (nominal $/kW-month)



All-in fixed costs were used in the capacity model in a few ways. First, it is one of the components in determining the FCM bids. The all-in costs of new generation will also guide the Cost of New Entry ("CONE") in the FCM, which sets the price cap and administrative pricing levels in the FCM under certain conditions, and it will also guide the bids of new entrants in the FCM. The all-in fixed costs are also used as a benchmark to determine whether new entry is economic, as discussed further below.

5.13 Levelized all-in costs of new generation

If I further incorporate the plant's running regime, i.e., load factor, all-in fixed cost can be presented in another form – as the "break-even" costs or new entry trigger prices. I employ a New Entry Trigger Price ("NETP") model that calculates these all-in levelized costs, assuming a certain amount of time for capital recovery and assuming a certain operating regime (i.e., load factor) to benchmark and test our energy price projections.

The NETP model covers capital, financing and operating costs and has six main components:

- amortized carrying charge of the plant over the debt term, which looks at the interest expenses based on all-in capital cost during construction term, levelized over debt term, and adjusted in $ per MWh terms using the plant's optimal operating regime.
- cost of debt , one element of the cost of capital;
- cost of equity, second element of the cost of capital;
- fuel cost;
- variable operating and maintenance costs (VO&M); and
- fixed operating and maintenance costs (FO&M), generally estimated as $/kW per annum and then adjusted in $/MWh terms using the plant's optimal operating regime.

For illustrative purposes, the tables below list the assumptions for the all-in breakeven costs for generic CCGT and generic (on-shore) wind generation.

Figure 82. All-in breakeven cost assumptions for gas-fired CCGT

analysis year	2014	2019	2023
leverage		60%	
debt interest rate		8.5%	
after-tax required equity return		16.0%	
corporate income tax rate		40%	
debt financing term		20 years	
equity contribution capital recovery term		20 years	
construction time		36 months	
average annual load factor		70%	
nominal capital cost, $/kW	$ 960	$ 1,039	$ 1,125
heat rate, Btu/kWh	6,861	6,792	6,724
nominal variable O&M, $/MWh	$ 1.8	$ 2.0	$ 2.2
CO2 adder, $/MWh	$ 6.2	$ 6.6	$ 7.4
nominal fixed O&M, $/kW/year	$ 22.7	$ 25.1	$ 27.1
new entry trigger price (NETP), $/MWh	$ 94.6	$ 101.9	$ 112.9

Figure 83. All-in breakeven costs assumptions for wind

analysis year	2014	2019	2023
leverage		60%	
debt interest rate		8.5%	
after-tax required equity return		16.0%	
corporate income tax rate		40%	
debt financing term		10 years	
equity contribution capital recovery term		10 years	
construction time		20 months	
average annual load factor		35%	
nominal capital cost, $/kW	$ 2,164	$ 2,341	$ 2,534
heat rate, Btu/kWh	n.a.	n.a.	n.a.
nominal variable O&M, $/MWh	n.a.	n.a.	n.a.
CO2 adder, $/MWh	n.a.	n.a.	n.a.
nominal fixed O&M, $/kW/year	$ 34.0	$ 37.5	$ 40.6
PTC, $/MWh	$ 21.0	$ 21.0	$ 21.0
REC, $/MWh	$ 20.0	$ 20.0	$ 20.0
new entry trigger price (NETP), $/MWh	$ 132.4	$ 143.5	$ 155.3