STATE OF CONNECTICUT
CONNECTICUT SITING COUNCIL

THE CONNECTICUT LIGHT AND POWER COMPANY APPLICATION FOR CERTIFICATES OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC NEED FOR THE CONNECTICUT VALLEY ELECTRIC TRANSMISSION RELIABILITY PROJECTS WHICH CONSIST OF (1) THE CONNECTICUT PORTION OF THE GREATER SPRINGFIELD RELIABILITY PROJECT THAT TRAVERSES THE MUNICIPALITIES OF BLOOMFIELD, EAST GRANBY, AND SUFFIELD, OR POTENTIALLY INCLUDING AN ALTERNATE PORTION THAT TRAVERSES THE MUNICIPALITIES OF SUFFIELD AND ENFIELD, TERMINATING AT THE NORTH BLOOMFIELD SUBSTATION; AND (2) THE MANCHESTER SUBSTATION TO MEEKVILLE JUNCTION CIRCUIT SEPARATION PROJECT IN MANCHESTER, CONNECTICUT.	**DOCKET 370**
And	
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.	**JANUARY 15, 2010**

BRIEF OF ISO NEW ENGLAND INC.

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BRIEF OF ISO NEW ENGLAND INC.

SUMMARY

ISO New England Inc. (the "ISO"), an intervenor in the above-captioned proceeding, offers the following summary of its position as set forth in this brief:

1. The ISO is the Reliability and Planning Authority for New England's regional electric system and is responsible for determining system needs;

2. The ISO has determined, in accordance with applicable planning procedures, that the system is now in need of action to eliminate violations of national and regional reliability standards and criteria;

3. The ISO has reviewed the proposed GSRP and MMP projects and has determined that they meet the system's identified needs;

4. The ISO planning process is consistent with Connecticut's IRP process, which has been completed for 2009;

5. The ISO supports the Application and believes that the GSRP and the MMP should be approved.

A non-profit organization without stockholders, the ISO is not motivated by money or the prospect of financial gain to participate in this proceeding, nor is its testimony steered by compensation toward a particular result. Instead, reliability is the ISO's top priority and its bottom line.

BACKGROUND

On October 20, 2008, The Connecticut Light and Power Company ("CL&P" or the "Applicant") filed an application (the "Application") with the Connecticut Siting Council (the "Council") pursuant to §§16-50k(a) and 16-50l(a) of the Connecticut General Statutes ("CGS") for a certificate of environmental compatibility and public need (the "Certificate") pertaining to the Connecticut portions of a proposed set of improvements to the electric transmission systems in north central Connecticut and western Massachusetts known as the Greater Springfield Reliability Project ("GSRP"). A companion application has been filed by CL&P's affiliate,[1] Western Massachusetts Electric Company ("WMECO") with the Massachusetts Energy Facilities Siting Board ("EFSB") for the EFSB's approval of those portions of the GSRP situated in Massachusetts. The Application also requests that the Council issue a certificate of environmental compatibility and public need for a separate but related project known as

[1] CL&P and WMECO are wholly-owned subsidiaries of Northeast Utilities ("NU"). (CL&P Ex. 1, Application, p. ES-1)

the Manchester to Meekville Junction Circuit Separation Project ("MMP", together with the GSRP sometimes referred to as the "Reliability Projects").

The GSRP consists of 35 miles of new 345,000-volt ("345kV") overhead line, 12 miles of which are in Connecticut, construction and upgrades of 27 miles of new and existing 115,000-volt ("115kV") overhead lines in Massachusetts, and substation improvements in both states, including the North Bloomfield Substation in Connecticut.[2] The Connecticut portion of the GSRP 345kV line would run from the North Bloomfield Substation to the Massachusetts border.

CL&P and WMECO propose that the GSRP's new 345kV line be constructed from the Ludlow Substation to the Agawam Substation and then to the North Bloomfield Substation, thus completing, in combination with an existing 345kV line from North Bloomfield to the Barbour Hill Substation, a 345kV loop through north central Connecticut and western Massachusetts (the "Northern Alternative"). Because WMECO is required to present a geographically distinct alternative to the EFSB, a variant of the proposed route would involve a new 345kV line from the Ludlow Substation to Hampden Junction and then roughly along the state border, including about 5.4 miles in Connecticut, to the Agawam Substation (the "Southern Alternative").

The MMP, which would cover approximately 2.2 miles, entails the separation of a 345kV circuit and a 115kV circuit between the Manchester Substation and Meekville Junction in Manchester, Connecticut.[3]

In response to a reactive Request for Proposals ("RFP") issued by the Connecticut Energy Advisory Board ("CEAB"), NRG Energy Inc. ("NRG"), submitted an application

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[2] CL&P Ex. 1, Application, ES-5.

[3] *Ibid.*

pursuant to CGS §16-50*l*(A)(3) for consideration of a 530 megawatt ("MW") combined cycle generating plant in Meriden, Connecticut.

The ISO requested intervenor status in this proceeding on November 21, 2008, pursuant to CGS Sections 16-50n and 4-177a and Section 16-50j-15a of the Regulations of Connecticut State Agencies ("RCSA"), and the Council granted the ISO's request on December 4, 2008. The ISO's interest is based on its role as both the independent system operator of the New England transmission system and the Regional Transmission Organization ("RTO") responsible for regional planning throughout New England, including assessing system needs, and the reliable operation of the New England regional power system. Specifically, the ISO is concerned for the reliability of the bulk power system serving the Greater Springfield Area,[4] including western Massachusetts and north central Connecticut.

The Council is charged under CGS Section 16-50p with the responsibility of determining both the public need for the Applicant's proposal and their probable environmental impacts and then assessing whether the environmental impacts are sufficient reason to deny the Application. The ISO's expertise in this proceeding is most relevant to issue of need from a planning and reliability perspective, so its participation has been geared toward providing assistance to the Council's consideration of the public need for the Reliability Projects. The ISO will comment primarily on these matters, leaving discussion of environmental issues, which it fully respects, to other participants.

[4] As used herein, "the Greater Springfield Area" includes and refers to the electrical system serving north central Connecticut and western Massachusetts because, from an electrical perspective, it is a single system serving the combined load pocket in that geographic area and has been so treated since the 1920's. *See* CL&P Ex. 43, Response to CSC-03-005.

DISCUSSION

I. The ISO Is the Reliability and Planning Authority for New England's Regional Electric System and Is Responsible for Determining System Needs

The ISO was established to be the independent system operator of the New England transmission system on July 1, 1997, and as such, it is responsible for the reliable daily operation of the New England power grid[5] and has exclusive authority from the Federal Energy Regulatory Commission ("FERC") for transmission planning throughout the New England region.[6]

On February 1, 2005, the FERC granted RTO status[7] to the ISO, providing it with broader authority for its functions. As an RTO, the ISO undertakes the role of security coordinator for the New England region and must comply with principles set forth by the FERC for such organizations.[8] As security coordinator, the ISO must ensure reliability of system operation and is responsible, among other things, for performing load-flow and stability studies to anticipate, identify and address security problems and directing actions to maintain reliability.[9] The FERC has concluded that the RTO must perform its

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[5] *New England Power Pool, Order Conditionally Authorizing Establishment of as Independent System Operator and Disposition of Control Over Jurisdictional Facilities*, 79 FERC 61,374 (1997) (authorizing formation of ISO New England Inc.); *Promoting Wholesale Competition Through Open Access, Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC 31,306 (1996) (establishing principles for ISO's operation and governance).

[6] *ISO New England Inc. & New England Power Pool, Order on Rehearing Requests and Compliance Filings*, 95 FERC 61,384 (2001) (authorizing ISO to oversee regional transmission planning); ISO Ex. 4, Mezzanotte PFT, pp. 7-8.

[7] *Order Authorizing RTO Operations*, ISO New England Inc. et al, Docket No. RT04-2-005, 110 FERC ¶ 61,111

[8] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000) Docket No. RM99-2-000

[9] *Id.* at 278-79.

functions consistent with established NERC reliability standards[10] and further, in order to ensure that transmission planning and expansion result in least cost outcomes, that:

> ...the *RTO must have ultimate responsibility for both transmission planning and expansion within its region* that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities.[11] (*emphasis added*)

The FERC has also affirmed the obligations of transmission providers regarding transmission upgrades and expansion:

> Because an RTO may not own all of the facilities it operates, we clarify that nothing in this Rule relieves any public utility of its existing obligation under the pro forma transmission tariff to expand or upgrade its transmission system upon request.[12]

The FERC's requirements are reflected in the Transmission Operating Agreement (the "TOA") among the ISO and participating transmission owners ("PTOs"), including CL&P, effective when the ISO became an RTO on February 1, 2005. The TOA recites that the ISO will be responsible for regional system planning[13] and Section 3.02(c) of the TOA states that the ISO shall act as the Reliability Authority for the New England transmission system. Schedule 3.09(a) of the TOA requires a PTO to construct any new transmission facility or upgrade designated in the ISO's Regional System Plan ("RSP"), and PTOs must comply with the ISO's planning procedures.[14]

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[10] *Id.* at 323.

[11] *Id.* at 486.

[12] *Ibid.*

[13] CSC Admin Notice Item 54, "Transmission Operating Agreement" among ISO New England and Participating Transmission Owners. ISO-NE. February 1, 2005 ("TOA"), p. 1.

[14] *Id.* at Sched. 3.09(a), Sections 1.1(a), 2.3.

The FERC's requirements are further imported into the ISO's Open Access Transmission Tariff (the "OATT"),[15] which is Section II of the ISO's Transmission, Markets and Services Tariff. Section II.46 of the OATT provides that a reliability transmission upgrade may be required as part of the RSP. The RSP process is prescribed in Attachment K[16] to the OATT, which sets forth the ISO's responsibility for regional transmission planning in New England and requires the ISO to assess the needs of the regional system to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures.[17]

The RSP is a comprehensive annual system planning report that is developed through a process open to a wide variety of stakeholders, including state regulators, consumer advocates, transmission customers, utilities and market participants, all of whom have the opportunity to provide input through the Planning Advisory Committee ("PAC"), a stakeholder group for which the ISO holds periodic planning meetings throughout the year.[18] Because of the RSP process and PAC input, the ISO brings to the Council in this proceeding the results of an evaluative process which involves expertise, objectivity, openness and inclusivity.

As part of the RSP process, the ISO conducts regular and ongoing assessments of the adequacy of the regional system in accordance with criteria set forth in Section 4.1 of Attachment K. Such needs assessments analyze, among other things, whether

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[15] CSC Admin Notice Item 34, "ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3." ISO-NE, July 15, 2009, Section II.

[16] CSC Admin Notice Item 32, "Planning FERC Electric Tariff No. 3, Open Access Transmission Tariff, Section II – Attachment K – Regional System Planning Process." ISO-NE. December 7, 2007.

[17] *Id.* at Section 1.

[18] ISO Ex. 4, Mezzanotte PFT, pp. 8-9.

transmission system facilities meet applicable reliability standards and have adequate transfer capability to support local, regional, and inter-regional reliability. Needs assessments are reviewed at PAC meetings to obtain input from PAC participants regarding the procedures and assumptions used in such assessments.[19] Needs assessments, along with the RSP, must incorporate market responses that have met specified criteria designed to assure certainty in delivering proposed resources,[20] and the ISO looks first to the marketplace for solutions to identified needs. Market responses may include generation, distributed generation, demand response and conservation. Thus, the RSP serves to assess and identify system needs and signal the need for market responses to identified needs.

Where market responses incorporated into a needs assessment are insufficient to eliminate identified needs, the ISO shall conduct a solutions study, pursuant to Section 4.2(b) of Attachment K, to develop regulated transmission solutions for such needs. The ISO may conduct needs assessments and solutions studies in concert with affected transmission owners, and the ISO has the authority, both under the TOA, as cited above, and pursuant to Attachment K, to obligate the appropriate transmission owner or owners to construct necessary transmission upgrades.[21] Although the ISO welcomes market responses, it has no authority to require the construction of generation or the implementation of any market response.

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[19] CSC Admin Notice Item 32, Attachment K, Section 4.1(f).

[20] *Id.* at Section 4.2(a), which provides that only such market responses shall be considered as: (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request for Proposals, or (iii) have a financially binding obligation pursuant to a contract.

[21] *Id.* at Section 8.

II. The ISO Has Determined that the System Is Now in Need of Action to Eliminate Violations of National and Regional Reliability Standards and Criteria

A. The ISO, pursuant to applicable procedures and standards, has determined that reliability needs exist.

In accordance with provisions of the ISO Tariff which are now essentially embodied in Attachment K,[22] the ISO, together with CL&P, conducted both a needs assessment[23] (the "Needs Analysis") and a solutions study[24] (the "Options Analysis") with respect to reliability issues in the Greater Springfield Area and potential solutions. The Needs Analysis was updated through a June, 2009 Addendum Report (the "Addendum")[25] to consider the ISO's Second Forward Capacity Auction ("FCA2") and the ISO's 2009 peak load forecast. These evaluations and studies result from the application of the ISO's expertise and experience in transmission system planning and operation to mandatory reliability criteria and standards established by the North American Electric Reliability Corporation ("NERC"), the Northeast Power Coordinating Council ("NPCC")[26] and the ISO,[27] utilizing assumptions and parameters which have been reviewed and vetted by various stakeholder and regulatory participants through the

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[22] The predecessor provisions were contained in Section 48 of the ISO Tariff, as previously in effect.

[23] CL&P Ex. 1, Vol. 5, Ex. 1, "Southern New England Transmission Reliability Report 1, Needs Analysis".

[24] *Id.*, Ex. 2, "New England East-West Solutions, Report 2, Options Analysis".

[25] CL&P Ex. 14, Supplemental Response to OCC Interrogatories, Set One, Question 9, dated June 22, 2009 (the "Addendum").

[26] CSC Admin Notice Item 35, "Document A-02 – Basic Criteria for Design and Operation of Interconnected Power Systems." Northeast Power Coordinating Council. Revised May 6, 2004 ("NPCC A-2").

[27] CSC Admin Notice Item 30, "Planning Procedure No. 3 (PP-3) Reliability Standards for the New England area Bulk Power Supply System." ISO-NE. June 11, 2009, Section 3.

open PAC process. GSRP needs were discussed at five PAC meetings from May, 2005, to June, 2009, and in other stakeholder forums as well.[28]

The Needs Analysis demonstrated that the transmission system serving the Greater Springfield area, including portions of north central Connecticut, is in violation of NERC reliability standards that became mandatory in 2005.[29] As regional reliability standards are required to be at least as stringent as national criteria, without the proposed project, the Greater Springfield area system would be out of compliance with regional criteria established in NPCC Document A-2 ("NPCC A-2") and Section 3 of the ISO's Planning Procedure 3 ("PP3").

While only one violation of NERC, NPCC or ISO reliability standards would cause an electrical system to be considered out of compliance,[30] the Needs Analysis, as updated by the Addendum, shows a high number of thermal and voltage violations resulting from either N-1 or N-1-1 contingency events, including voltage violations that could lead to voltage collapse of the Greater Springfield system and outages cascading into neighboring states, including Connecticut.[31]

The Needs Analysis was performed strictly in accordance with the transmission planning study methodology prescribed by Section 3 of PP3. Assumptions used in the study emanated from the working group, were discussed with the PAC and were

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[28] *See* CSC Admin Notice Item 57, "Planning the New England Transmission System for Reliable Operation," ISO-NE, August 11, 2009, p. 22.

[29] CL&P Ex. 1, Vol. 1, p. F-4.

[30] ISO Ex 4, Pre-filed Testimony of Frank W. Mezzanotte, July 7, 2009, p. 13.

[31] *Ibid.* Because the Addendum contains Critical Energy Infrastructure Information ("CEII"), the ISO will simply call attention to the Addendum itself, particularly Sections 2.2 and 2.3 and Tables 2-5, pp. 5-20, for a summary of reliability violations. *See also* 7/21/09 Tr. 48-50.

determined by the ISO, which has the ultimate responsibility for choosing dispatch scenarios and other planning assumptions (10/27/09 Tr. 207;10/28/09 Tr. 158, 165), to be reasonable and appropriate.[32] It does not appear that anyone who now questions the planning assumptions of the Needs Analysis registered any questions or sought further information regarding such assumptions at PAC meetings. (10/22/09 Tr. 74-75; 10/27/09 Tr. 43-44; 10/28/09 Tr. 165)

The ISO believes that reliability problems in the Greater Springfield Area are rooted in aging and transmission infrastructure that is inadequate to serve load and move power. (10/27/09 Tr. 161) There are a number of contingencies in Springfield which result in both short-term emergency limit ("STE") overloads and drastic action limit ("DAL") overloads. An STE rating is a 15 minute rating, while a DAL rating is five minutes. (*Id.* at 183-85) These short timeframes do not provide sufficient reaction time for operators and carry the potential for severe equipment damage.

The system is already on the edge of its operational capability to meet peak demand in the event of multiple contingencies and extreme weather conditions (10/28/09 Tr. 26), and there is an increasingly high risk that the system will be unable to withstand single and multiple element contingencies following the loss or outage of certain critical facilities in Greater Springfield and north central Connecticut as the system approaches forecasted peak load levels.[33] There is a compelling public need to upgrade transmission, and the appropriate upgrade, based on the Options Analysis conducted by the ISO and CL&P to identify possible solutions, is the proposed GSRP, along with its companion MMP project.

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[32] Furthermore, in commenting on the dispatch scenarios used in the Application, Mr. Mezzanotte indicated that reliability violations were shown in all three dispatches. (10/27/09 Tr. 214)

[33] ISO Ex. 4, Mezzanotte PFT, p. 11.

The GSRP, as a component of the New England East West Solution ("NEEWS") or the Southern New England Reliability Project ("SNETR") as it was previously called, was first studied by the ISO in 2005 and was listed as a needed regional transmission upgrade in the Regional System Plan for 2006. ("RSP06") It has been listed as a needed upgrade in each RSP since that time, including RSP09, which was released in October, 2009.[34]

B. The identified reliability needs satisfy Connecticut precedent regarding public need.

While there is no statutory definition of "public need," at least one reviewing court has cited the dictionary definition of "need" as "a necessary duty" or "a want of something requisite, desirable or useful." *Citizens for Defense of Oxford v. Connecticut Siting Council*, 2000 WL 1785118 Conn.Super (Nov. 14, 2000) at p.3. That electricity is essential to Connecticut's quality of life and economic stability, something that is indeed "requisite, desirable or useful," is inarguable. Homes need electricity for cooking, washing, cleaning, communicating, studying and sometimes staying warm. Businesses large and small depend on it in a computerized age to conduct operations, buy and sell goods and services, transfer funds and keep records – in short, to function. The Connecticut Business and Industry Association, as a participant in Council Docket No. 217 (regarding the siting of the Bethel-Norwalk 345kV line), indicated that 43% percent of respondents in a survey of 4,000 businesses across the state would consider an electric

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[34] CSC Admin Notice Item 50, 2009 Regional System Plan. ISO New England Inc. October 15, 2009, pp.140-43.

outage of just one hour's duration "serious or catastrophic," triggering losses of up to $100,000 in half of them.[35]

A facility has been found to meet a public need where it enhanced the reliability of the electric system and contributed to the need to meet forecast requirements. *Town of Preston v. Connecticut Siting Council*, 20 Conn.App. 474, 568 A.2d 799 (1990). The Council's determination of public need has also been upheld where a proposed facility would improve system performance. *Town of Westport v. Connecticut Siting Council*, 47 Conn.App. 382, 797 A.2d 655 (2001).

The record in this case is replete with evidence that the power system serving the Greater Springfield Area, including north central Connecticut, does not meet reliability criteria and that the Projects will enhance system performance and ensure compliance with national reliability standards and regional reliability criteria. The record thus compels a finding of public need for the GSRP and the MMP.

C. The OCC has not demonstrated a lack of need for the Reliability Projects

Opponents of the GSRP have assembled loosely two lines of argument against it. While the argument for further study is mild, the more radical argument posits that there is no need for the GSRP and the MMP. The latter argument has been advanced in this proceeding solely by a source plainly unqualified to render a professional opinion regarding electric system reliability.

The witness put forward by the Office of Consumer Counsel (the "OCC"), Mr. Paul Chernick, is by his own admission not an expert with respect to transmission reliability, transmission modeling, the stress testing of transmission systems or reliability evaluations of

[35] CSC Admin Notice Item 47, Connecticut Siting Council Docket No. 217, 1/15/03 Tr. 142, 154; CBIA Ex. 1, 2

electric transmission systems (10/22/09 Tr. 16-17, 21), has never performed and cannot perform load flow modeling or conducted other analyses or studies customarily used to determine transmission reliability (10/21/09 Tr. 18, 20;10/22/09 Tr. 16, 28), has not worked for a utility or other entity responsible for reliable electric service (10/21/09 Tr. 20), has no planning or operational experience regarding electric transmission and distribution systems (*Id.* at 18, 20; 10/22/09 Tr. 62), has never witnessed control room operation during an emergency (*Id.* at 65), has no college course work in electrical engineering beyond his sophomore year and none at all in transmission planning or power engineering (10/21/09 Tr. 17), has taken no other training regarding electric system planning or operation (*Ibid.*), is not a registered Professional Engineer (*Ibid.*) and does not even possess an engineering degree. (*Id.* at 16; 10/22/09 Tr. 21)

While Mr. Chernick has testified, apparently as an expert witness, in over 200 regulatory proceedings,[36] it appears that less than a handful of such proceedings involved the reliability needs of electric systems,[37] the instant proceeding being perhaps only the third. In two prior siting proceedings, the Council[38] and also the Vermont Public Service Board[39] have approved proposed facilities despite his recommendations that they should be deferred or studied further. He has also taken issue with the support of the Connecticut Department of Public Utility Control (the "DPUC"), as expressed in the DPUC's 2008

[36] OCC Ex. 1, Chernick PFT, p. 2.

[37] *See* OCC Ex. 2, Resume of Paul Chernick. Mr. Chernick appears to have testified mainly with respect to rates, utility economic matters and integrated resource planning.

[38] *See* CSC Admin Notice Item 47, Connecticut Siting Council Docket No. 217.

[39] Vermont Public Service Board Docket No. 6860, *Petition of Vermont Electric Power Company, Inc. ("VELCO") for a Certificate of Public Good authorizing VELCO to construct the so-called Northwest Vermont Reliability Project*, January 28, 2005.

Integrated Resource Plan Decision,[40] for NEEWS (10/21/09 Tr. 83) and with the CEAB Evaluation Report's conclusion[41] that the GSRP and MMP are reasonable solutions, absent market response, to the reliability problems addressed by the Application. (*Id.* at 186, 188)

In evaluating Mr. Chernick's views regarding the studies performed by the ISO and the Applicant, the Council should consider his rather unimpressive electrical engineering background against those of the electrical engineering experts at the ISO and CL&P.

Before examining Mr. Chernick's position, it is helpful to note that he does not challenge the professionalism of the ISO's transmission planning staff, nor does he take issue with the ISO's load flow modeling program or the results obtained from the load flow simulations it ran, based on the modeling inputs. (10/22/09 Tr. 35-36) Furthermore, he accepts that, given the inputs and assumptions used in the modeling, the results of the load flow simulations show violations of reliability criteria in the Greater Springfield area and in north central Connecticut as summarized in Sections 2.2 and 2.3 and Tables 2 through 5 of the June, 2009 "GSRP Addendum Report Incorporating the FCA-2 Results and the 2009 CELT Forecast" (the "Addendum")[42] prepared by CL&P as an update to the Needs Analysis. (*Id.* at 37, 39) He has no disagreement with NERC reliability standards, reliability criteria under NPCC Document A-2 or the ISO's PP3 reliability standards. (10/21 Tr. 25-26, 28-29)

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[40] In its Decision in Docket 08-07-01, *DPUC Review of the Integrated Resource Plan*, (the "2008 IRP Decision")the DPUC stated: "The Department gives considerable weight to the ISO-NE finding that NEEWS is needed for system reliability." (*Id.* at p.41)

[41] CEAB Ex. 1, Connecticut Energy Advisory Board Evaluation Report, dated February 17, 2009, p. 26.

[42]CL&P Ex. 14, Supplemental Response to OCC Interrogatories, Set One, Question 9, dated June 22, 2009 (the "Addendum").

The areas of Mr. Chernick's disagreement with the analysis performed by the ISO and CL&P fall broadly into two categories: he believes the assumptions in the dispatch cases used in the load flow modeling do not stress the system reasonably and he also believes operational response should be factored into planning assumptions.[43] While Mr. Chernick may be satisfied if the system passes an easy test, the ISO does not believe a horse that cannot go the distance becomes a better performer simply by shortening the course and changing the jockey.

1. The Dispatch Scenarios and Study Assumptions Reasonably Stress the System.

Mr. Chernick's dissatisfaction with the dispatch assumptions centers upon his belief that they place unrealistic stress on the system, and he attempted to support his position by noting the improbability under dispatch scenarios D1 and D3 of several generating units being unavailable at the same time under summer peak weather conditions.[44] The easy answer to Mr. Chernick's complaint is that reliability violations occur under all dispatch scenarios (10/27/09 Tr. 214), including D2, in which all critical large units are on and generation output is maximized.[45] Therefore, whether or not he disputes dispatch scenarios D1 and D3 as being unrealistic, reliability violations found under D2 would have to be resolved.

Mr. Chernick's foray into probabilities also runs afoul of prescribed transmission planning methodology under Section 3 of PP3, which requires that design studies for transmission planning be done on a deterministic basis.[46] The ISO conducts its transmission

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[43] OCC Ex. 1, Chernick PFT, p. 10

[44] *Id.* at 21.

[45] CL&P Ex. 14, Addendum, p. 4.

planning studies on a deterministic basis (*Id.* at 206-07, 211), and NRG's witness, Mr. Stein, also agreed that transmission planning is done on a deterministic basis (*Id.* at 90). Perhaps the most forceful statement that transmission planning must be done deterministically came from Mr. Chernick himself:

> Deterministic testing is required because probabilistic analysis is too complicated and can't be done. I have not advocated probabilistic analysis. (10/22/09 Tr. 90)[47]

It is therefore quite puzzling that the OCC's witness should choose to play a contradictory game which would allow him to run the ball out of deterministic bounds into the area of probability[48] and then re-emerge in the end zone, claiming to have scored points against the application of transmission reliability standards. Regardless of probabilities, multiple contingencies are a reality. On January 22, 2003, Southwestern Connecticut and Norwalk-Stamford suffered outages of eight units representing 1,038 MW, close to 40% of the 2700 MW installed capacity of these subareas.[49] The Great Northeast Blackout of August 14, 2003, happened, however unlikely. (10/22/09 Tr. 89) Fires, explosions and

[46] Section 3 of PP3 should be contrasted with the resource adequacy provisions of Section 2 of PP3, dealing with loss of load expectations and generation adequacy, which specifically refers to probability and directs that, "Compliance with this criteria shall be evaluated probabilistically..." There is no similar statement in Section 3, nor should there be any confusion between the separate requirements of resource adequacy covered by Section 2 of PP3 and the transmission security requirements addressed by Section 3 of PP3. LOLE analysis only assesses system capacity from a generating standpoint; it does not address transmission reliability or the system's ability to get generation to the load. Just as a running engine does not mean a used car has adequate steering or good tires which can get it where it needs to go, the fact that no problem arises under an LOLE analysis does not mean that the power system has no reliability problems. (1/16/03 Tr. 36-37).

[47] Mr. Chernick also said, "I don't believe anybody has a model that can run all of the probabilities of outages on various transmission lines and transmission components." (10/22/09 Tr. 67)

[48] Mr. Chernick has practiced this game before, having criticized the Northwest Vermont Reliability Project as involving a scenario of contingencies which had a likelihood of occurring one day every eight million years. (10/21/09 Tr. 65) The Vermont Public Service Board approved the project. Decision in Vermont PSB Docket No. 6860, *Petition of VELCO*, January 28, 2005. By comparison to his assessment of probabilities in Vermont, he assigns a far greater probability to the assumptions in this case. (OCC Ex. 1, Chernick PFT, p.21)

[49] CSC Admin Notice Item 47, CSC Docket 217, 1/22/03 Tr. 86-7, 176, 180.

lightning strikes can cause outages of indefinite duration. For these and other reasons, the rules for transmission security analysis under Section 3 of PP3 are clear, and they do not lend themselves to the liberties Mr. Chernick would like to take to evade resolution of reliability criteria violations in the electrical system serving Connecticut and its neighboring state.

While Mr. Chernick characterizes the stresses placed on the system by the dispatch scenarios as unrealistic and therefore unreasonable, Mr. Mezzanotte explained the study approach as one which basically sought to understand the system and how it would behave under a variety of changing conditions which might occur during the course of a year that has 8,760 hours, including different load levels, different system dynamics, different exports, different imports, different generation availability, and various lines out for maintenance. (*Id.* at 206-07) These dynamic activities and changes on the system cannot all be analyzed (*Ibid.*), so, as Mr. Mezzanotte noted, the dispatch scenarios used to stress the system in deterministic testing serve as a proxy[50] for all the undeterminable events that may occur in the extended life of a significant capital investment:

> I mean there's no way -- there's no way we can predetermine that there might be a danger tree out there or there may be a mis-operation of a relay that takes out a nuclear plant. So we try to stress the system through the dispatches primarily to -- as a sort of proxy for all these other events that we cannot predetermine because there would be no way we could come up with them. (*Id.* at 211)

Mr. Mezzanotte said that the working group began with eight scenarios and chose three which were representative of system behavior and deficiencies under a variety of conditions, including all generation on and power flows in different directions, and in his

[50] Mr. Chernick also stated that one set of events is looked at as a proxy for other sets of events which would have similar effects. (10/21/09 Tr. 61)

opinion,[51] the dispatch scenarios chosen satisfied the requirement of Section 3 of PP3 that the system be reasonably stressed. (10/27/09 Tr. 212-13)

A final point that rebuts Mr. Chernick's case for more lenient dispatch scenarios lies in the hierarchy of national and regional reliability standards. Mr. Chernick acknowledged that the ISO's reliability criteria had to be consistent with NPCC reliability standards and he also understood that the ISO's standards could be more stringent than NPCC's, in which case the more stringent standards would apply.[52] (10/22/09 Tr.32-33) The NPCC standard requires that design studies assume power flow conditions which utilize transfers, load and generation conditions which "stress" the system,[53] while the ISO criteria require that such conditions "reasonably stress" the system.[54] Mr. Chernick agreed that dispatch scenarios eliminating only one or two small generators would not "reasonably" stress the system. (*Id.* at 31) Combining the fact that the ISO's requirements must be at least consistent with the NPCC's standards and may be more stringent with Mr. Chernick's observation that eliminating too little generation would not be a reasonable stress of the system leads to one conclusion: the term "reasonable," as used in PP3, is meant if anything to apply a stricter

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[51] It bears mention that Mr. Mezzanotte holds a Master's degree in Power Engineering, is a registered Professional Engineer in three states, and has approximately 30 years of electrical engineering experience, including transmission planning, with utilities and the ISO. Ex.1 to ISO Ex. 4, Mezzanotte PFT.

[52] CSC Admin Notice Item 35, "Document A-02 – Basic Criteria for Design and Operation of Interconnected Power Systems." Northeast Power Coordinating Council. Revised May 6, 2004 ("NPCC A-2"). As stated in Section 2.0 of NPCC A-2:

> Member system or local conditions may require criteria which are more stringent than those set out herein. Any constraints imposed by these more stringent criteria will be observed. (*Id.* at p.2)

[53] CSC Admin Notice Item 35, NPCC A-2, Section 2.1, p.2.

[54] CSC Admin Notice Item 30, "Planning Procedure No. 3 (PP-3) Reliability Standards for the New England area Bulk Power Supply System." ISO-NE. June 11, 2009, Section 3.

standard in New England which will assure that the system will be subjected to real stress when tested.

Maintenance of the Connecticut import capability at 2,500 MW and 1,700 MW post-contingency in the transmission modeling in this case has also been questioned. There are at least two answers. First, the ISO must assure pursuant to Section I.3.9 of the Tariff,[55] that no system improvements, whether generation or transmission, will have an adverse impact on the system. (10/27/09 Tr. 228) Reduction of import capability would be an adverse impact on the system and it would constrain the ability of generators outside Connecticut to export into Connecticut. Accordingly, transfers are simulated at or near their established limits in modeling proposed additions to the system.[56] As Messrs. Kowalski and Mezzanotte testified, Connecticut has planned and relied on the ability to import 2,500 MW, but at times it is primarily an exporter of electricity to Massachusetts (*Id.* at 223-24), and it would not be appropriate from a planning perspective to build a lesser capability into a new facility which will be in service for a long time and should be able to satisfy future demands. (*Id.* at 226-27) Second, as Mr. Mezzanotte indicated, reliability criteria violations are still shown when modeling the import limits at 1,000 MW and all the way down to around 50 MW. (*Id.* at 227-28) Thus, even if the system were modeled at levels well below established transfer limits, contrary to the requirements of PP5-3, the results would still show reliability needs to be corrected.

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[55] CSC Admin Notice Item 34, "ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3." ISO-NE, July 15, 2009, Section I.3.9.

[56] *See* CSC Admin Notice Item 31, "Planning Procedure No. 5-3 (PP5-3), Guidelines for Conducting and Evaluating Proposed Plan Application Analyses," ISO-NE, February 1, 2005, Section 3.3.1.1(g).

2. Transmission Planning Cannot Rely on Operational Response Beyond PP3.

Mr. Chernick's second major argument that the GSRP and the MMP are unnecessary rests on his belief that operational response should be factored into the determination of need. He posits that the ISO could and would take operational steps in the wake of any contingency to prevent system outages and that as long as system outages are not too frequent or too lengthy, no expensive investment in the system is necessary. (10/21/09 Tr. 122-23)

The ISO appreciates Mr. Chernick's confidence and would of course take all appropriate steps to respond to contingencies and avoid system outages. It is, however, necessary to avoid confusing operational steps that might be taken in response to a contingency with operational responses which may be considered in planning studies. Section 3 of PP3, which guides and circumscribes planning studies, indicates that resources available in 10 minutes, phase-angle regulator control and HVDC control can be counted in responding to a contingency.[57] Mr. Chernick disagrees that Section 3 limits the operational responses a planner may consider; he would widen a planner's view beyond PP3 to include apparently all operational responses. (10/21/09 Tr. 115, 117) The ISO believes that would be neither permissible nor wise.

In arguing that long term improvements needed to address reliability concerns should be forestalled by operational action which may successfully avert an emergency today or tomorrow, Mr. Chernick shifts undue infrastructural weight onto the humans who operate a system in need of help. Given the very human dimension of operational response, the possibility of imprecision in judgment, communications or execution cannot be ignored.

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[57] *Ibid.*

It takes no particular expertise to recognize, as Mr. Chernick does, that emergency events and multiple contingencies create stressful circumstances for operators, and the best and most timely judgments might not always be exercised or effective results obtained. (10/22/09 Tr. 42-43) Furthermore, as system improvements are delayed despite increased system needs, operation of the system becomes a more complex task, as Mr. Kowalski testified. (10/27/09 Tr. 212) Mr. Chernick's faith in operational response is severely tested by his own admission, with which the ISO agreed (10/27/09 Tr. 186), that in certain events, such as very low voltage situations, an operator has only seconds, if any time at all, to take action to avoid dropping load (*Ibid*; 10/21/09 Tr. 129)

Load-shedding is a permitted operational response to an emergency under OP7,[58] and it may be undertaken at any time before during or after action during a capacity deficiency under OP4.[59] Load-shedding is essentially a blackout in that it results in loss of service. If transmission planning studies are to allow for all operational response in determining system needs, as Mr. Chernick advocates, then Connecticut will have to reckon with the prospect that its residents and businesses will be inconvenienced by loss of electricity instead of an improved system which meets reliability standards. It is up to human operators to decide how much load must be shed to avoid widespread outages, and it seems likely that more rather than less load would be shed in such circumstances. Faced with hundreds of different contingency scenarios, the system operator must act rapidly to determine how much load to shed to prevent the system from collapsing, and it would be

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[58] CSC Admin Notice Item 52, "Operating Procedure No. 7, Action in an Emergency," ISO-NE. August 18, 2008.

[59] *Ibid.*; CSC Admin Notice Item 33, "Operating Procedure No. 4 (OP-4), Action During a Capacity Deficiency," ISO-NE. March 5, 2008

hazardous to try to limit the impacts of load-shedding to as few customers as possible in a high stakes situation where cascading outages can result from shedding too little load. If 100 MW must be shed, up to 100,000 Connecticut households could be affected, and it is possible that sensitive installations, such as nursing homes, could be included in areas where electric supply is discontinued.

One must question whether Connecticut, presumably interested in economic development and satisfied residents, would deem interrupted electric service to be an attractive feature of its transmission system.

Recent history is incompatible with overconfidence in operational response. The Great Northeast Blackout which occurred on August 14, 2003 and spread eastward from Ohio to the borders of the New England region, where only 2,500 MW of load was lost,[60] was attributable to a combination of overloaded lines and operator error. Inquiry about the role of operator error drew a verbal shrug from Mr. Chernick:

> ...[I]t's my understanding that the operators in Ohio were not paying attention to what was going on and did not adjust the system as lines started to fail. They had the capability of doing it as I understand, but were not using that capability. (10/21/09 Tr. 124)

Given his frank admission that operator inattention caused one of the greatest blackouts in history, it is difficult to comprehend Mr. Chernick's reliance on operational response as a substitute in this proceeding for adherence to proper planning and mandatory national and regional reliability standards.

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[60] If one megawatt serves 1,000 households, such a loss in New England – much of which was in southwestern Connecticut – should not be minimized as it represents up to 2.5 million households without electricity.

A second instance of operational error also deserves comment. By Order dated October 8, 2009,[61] FERC approved a $25 million civil penalty against Florida Power and Light Company ("FPL") pursuant to the terms of a Stipulation and Consent Agreement among FERC's Enforcement Office, NERC and FPL (the "FPL Consent Agreement"). In addition to the monetary penalty, FPL was also required to take various reliability enhancement measures. The FPL Consent Agreement resolved an investigation into the causes of a February 26, 2008 blackout (the "Florida Blackout") which caused loss of service to approximately 950,000 customers in the lower two-thirds of Florida.[62] Service was restored to 56% of customers within one hour and all customers within three hours.[63]

While the FPL Consent Agreement resolved the investigation short of adjudicating whether or not FPL had violated any Reliability Standards, the FERC Order recited a number of Reliability Standards as being applicable to the FPL Consent Agreement, including, as different sets of standards, both the Transmission Operations group of Reliability Standards and the Transmission Planning group of Reliability Standards.[64]

While the penalty against FPL certainly commands attention, the most significant aspect of the Florida Blackout for purposes of this proceeding and evaluation of Mr. Chernick's proposal for broad consideration of operational response in transmission planning relates to the cause of the event. There was misunderstood communication between a field engineer and a load dispatcher regarding the disabling of protective equipment and thus a failure of communication from the load dispatcher to the system

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[61] CSC Admin Notice Item 53, "Florida Blackout, Order Approving Stipulation and Consent Agreement," Docket No. IN 08-5-000, 129 FERC ¶ 61,016 (2009).
[62] *Id.*, Attached FPL Consent Agreement, Section II.2, p. 1.

[63] *Id.* at Section II.16, p.4.

[64] CSC Admin Notice Item 53, Paragraphs 16 and 17.

operator.[65] As a result of the field engineer's activity and the miscommunication with the load dispatcher, a fault occurred, causing a 17 to19 second arc which spread to an adjacent circuit switcher, causing a three phase fault on the system.[66] The fault was cleared remotely in just 1.7 seconds, but it resulted in significant frequency swings, voltage excursions and the tripping of transmission and generation in the lower two-thirds of Florida.[67]

The Florida Blackout, caused by human error and miscommunication, may thus be summarized as follows: a 19 second problem, a 1.7 second operational response, a blackout of one to three hours and a $25 million fine. The Florida Blackout is again a reminder that widespread damage may be done to the electric system in a matter of seconds, and it teaches that even very fast operator response will not avoid costly problems. In considering the need to rectify reliability violations in north central Connecticut and western Massachusetts, it would not be wise to expand the consideration of operational response in transmission planning beyond what PP3 specifically allows.

There is also a dichotomy between operational and planning time horizons and information which Mr. Chernick fails to appreciate. Operators operate the system they have without concern for its adequacy to meet events that may occur years later, while planners have a responsibility to design a system that operators will be able to use without undue complexity for years. (10/27/09 Tr. 212) As Mr. Scarfone testified, operators have the ability to respond to events with a high degree of certainty as to the status of the system they are operating and greater foreseeability of the events which might require attention in a

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[65] *Id.*, FPL Consent Agreement, Sections 10, 11, p. 3.

[66] *Id.* at Section 12, p. 3.

[67] *Id.* at Section 13, p. 3.

typical day-ahead operating time frame. (7/21/09 Tr. 65-66) Planners, on the other hand, must make allowance for a much longer time frame and the possibility of events and changes which cannot be foreseen at the end of a ten year planning time frame (*Id.* at 162), let alone toward the end of a transmission facility's 30 to 40 year useful life. (10/28/09 Tr. 148) The difference between the long lead times required for the planning and construction of generation and transmission facilities versus the short lead times available for responding to changed operating conditions is recognized in PP3 as a basis for variances between operating rules and planning and design criteria.[68]

III. <u>The ISO Has Reviewed the Proposed GSRP and MMP Projects and Has Determined that They Meet the System's Identified Needs</u>

A. The Reliability Projects Are Part of a Long Term Plan and Will Meet the Identified Reliability Needs

While the Needs Analysis paints a very clear picture of the inadequacy and unreliability of the existing power system in the Greater Springfield Area and strongly supports a finding that there is a public need to improve the system in order to make it reliable, the Options Analysis indicates that the Reliability Projects constitute the best alternative for meeting this public need.

The Reliability Projects are consistent with a long term plan for the expansion of Connecticut's transmission system because they would eliminate reliability criteria violations, improve system performance, enable more generation to be built in Connecticut and elsewhere in New England, and enhance more efficient transport of

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[68] CSC Admin Notice Item 30, PP3, Section 1, p.1

power across the system. The ISO prefers the so-called "Northern Alternative" because it offers greater reliability.[69]

In particular, the GSRP will provide an alternative 345 kV source to the North Bloomfield Substation and establish a new 345/115 kV hub west of the Connecticut River and north of the North Bloomfield Substation at the Agawam Substation. The MMP will improve reliability by eliminating a double-circuit contingency that creates overloads on underground cables in Hartford.[70] The Reliability Projects will also eliminate the dependence of the Connecticut import capability on the availability of local generation west of Springfield. (10/27/09 Tr. 124-30)

No market response has come forward that could meet the needs identified by the Needs Analysis. NRG's proposed Meriden plant is too electrically remote from north central Connecticut and Springfield to meet those needs, and in the ISO's view, it is not a substitute for the GSRP and the MMP. (10/27/09 Tr. 196; 10/28/09 Tr. 18)

B. There is no further need to study reliability needs or solutions relating to the Greater Springfield Area System.

The GSRP has been the subject of study since at least 2005, when first introduced to the PAC. (10/21/09 Tr. 30; 10/27/09 Tr. 189, 191-92) The study process has adhered to the course set forth in the ISO's Tariff, notably Attachment K, which lays out the regional planning process. A Needs Analysis, as mandated by the ISO's Tariff, was undertaken by CL&P and the ISO to identify whether there were any reliability needs affecting the Greater Springfield area. As Mr. Mezzanotte testified, the best result would have been that no reliability needs were found. (10/28/09 Tr. 162) Once needs were identified, however, a

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[69] *Id.* at p. 14.

[70] ISO Ex. 4, Mezzanotte PFT, p. 16.

second study, the Options Analysis, was conducted in accordance with the Tariff to explore possible solutions to the needs. The studies have been presented to various ISO committees, and input and comment has been sought by the ISO at a number of PAC meetings.[71] The study results have been updated to account for the results of Forward Capacity Auctions conducted by the ISO and also recent load forecasts. (10/27/09 Tr. 161, 193-94)

Regional System Plans have included the GSRP since RSP05, thereby inviting market solutions as preferred alternatives to a transmission solution, but none came forward in response to the RSP or the PAC planning process. (10/28/09 Tr. 251) In October, 2009, RSP09 confirmed that the need for the GSRP and the MMP still exists. (*Id.* at 25)

The call for further study grows largely from the thin soil of a twin fallacy that mistakenly assumes first that the GSRP is being proposed for the purpose of improving Connecticut's import capability and second that, if the Meriden plant were to address the import capability issue, remaining reliability needs could then be mitigated by lesser projects than the GSRP and the MMP, perhaps not located in Connecticut.

As witnesses for both CL&P and the ISO have testified, the GSRP and the MMP are not being proposed for the purpose of increasing Connecticut's import capability, and Mr. Mezzanotte stated bluntly that if such were the purpose, the GSRP would not be justified. (10/27/09 Tr. 165-66; 10/28/09 Tr. 28-30, 76) Increased import capability is simply a side benefit that accompanies the principal benefits of the project. (7/29/09 Tr. 165; 10/27/09 Tr. 114, 165) Mr. Stein, testifying on behalf of NRG, indicated that the Meriden proposal was intended as an alternative to importing power into Connecticut, not to fixing problems in

[71] GSRP needs were discussed at five PAC meetings from May, 2005, to June, 2009, and in other stakeholder forums as well. *See* CSC Admin Notice Item 57, "Planning the New England Transmission System for Reliable Operation," ISO-NE, August 11, 2009, p. 22.

Springfield (10/27/09 Tr. 49, 80), and he advocated further study to determine what need there was to increase Connecticut import capability and to determine what needs there were absent the need to increase import capability. (*Id.* at 13-14) It is thus apparent that NRG had inaccurately assumed increased import capability to be a principal reason for the GSRP and based its request for a study on that misinterpretation. (*Id.* at 39-40, 42) Given the clarification that increased import capability is not the reason for the GSRP, no further study can be justified on this faulty premise.

Nonetheless, there lingers a stubborn idea that further study might indicate whether the Meriden plant would mitigate identified needs and thus result in lesser or different projects than the GSRP and MMP to address any remaining reliability problems. (*Id.* at 40) Any such study, which would of course entail time[72] and money, is unnecessary. Mr. Kowalski testified that the proposed Meriden plant is irrelevant to the needs that will be resolved by the GSRP and the MMP and will have no mitigating impact on those needs. (10/28/09 Tr. 90, 97, 101) While of potential benefit to Connecticut broadly, given its central location in the state (*Id.* at 17-18),[73] the Meriden plant would be too electrically remote to resolve problems in north central Connecticut and western Massachusetts. (*Id.* at 18) Those problems will still exist, and a transmission solution will be needed, whether the Meriden plant is built or not. (*Id.* at 18, 97)

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[72] There has been, as noted by the DPUC in its IRP decision in commenting on the "late stage" of proceedings, adequate opportunity for parties to present alternatives to NEEWS and its components in either the IRP process or the ISO process, yet none were presented. It is doubtful that any meaningful information could be adduced from further study within the statutory time limit for the Council to render its decision in this proceeding, and rejection of the Application simply for the purpose of further study would in all probability lead to the time and expense of a renewed application to the Council.

[73] Mr. Kowalski declined to speculate on whether generation located elsewhere, such as Bloomfield, would help to resolve problems in north central Connecticut (10/28/09 Tr. 97), and such speculation would be pointless as no such facility has been proposed or is under consideration.

Some requests for further study even appear to be strategically driven by certain generation interests which hope, if the Council denies the Application,[74] to gain traction in the DPUC's next Integrated Resource Plan ("IRP") process.[75] The ISO, which obviously respects generation resources (10/27/09 Tr. 225; 10/28/09 Tr. 19) and welcomes all megawatts, whether produced or saved,[76] would nevertheless suggest that the Council should not hold reliability needs hostage to hopes of commercial advantage, especially where there is no certainty attached to generation proposals[77] and no commitment to build. (*Id.* at 255)

The Citizens Against Overhead Power Line Construction ("CAOPLC") urged that an HVDC line be studied as an alternative to an overhead line for a portion of the GSRP route, particularly in the Town of Suffield. CAOPLC has neither studied this possibility itself nor contacted the ISO in this regard to date. However, as was made clear in Docket 272,[78] HVDC lines have limited application, as for example the connection of asynchronous systems, use in underwater cables, and long distance connections between separate power systems. HVDC, when integrated into a single power system, offers less flexibility of interconnection with other lines, cannot relieve overloads which may occur on other lines in

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[74] Mr. Kowalski testified that if the GSRP were denied, the ISO and CL&P would work an another solution to the identified needs (10/28/09 Tr. 48) and Mr. Rourke added that FERC would have to be notified of the rejection. (Id. at 49)

[75] *See*, e.g., testimony of NRG witnesses Fuller and Gordon. (10/22/09 Tr. 226; 10/27/09 Tr. 25-26)

[76] As Mr. Stephen Whitley, the ISO's former President and Chief Operating Officer, assured the Council in Docket 217, he loves every megawatt just the same, whether it comes from generation, load reduction or elsewhere. (CSC Admin Notice Item 47, Connecticut Siting Council Docket No. 217, 1/16/03 Tr. 238; 1/22/03 Tr. 104.

[77] NRG stated that the markets are not in a position to support investment today and admitted that there is no guarantee that it will receive a contract for the Meriden plant or that it would be selected by the DPUC in connection with the 2010 IRP. (10/22/09 Tr. 228; 10/27/09 Tr. 37, 47)

[78] CSC Admin Notice Item 45, Connecticut Siting Council Docket No. 272

the system and entails more operational complexity. (10/28/09 Tr. 142) The ISO does not believe HVDC is appropriate for use in connection with, or as part of, the GSRP.

No one in this proceeding has called into question the engineering expertise or seasoned professionalism of the ISO's planners, not even Mr. Chernick. (10/22/09 Tr. 13) Each of the ISO's three planning witnesses has stated that no further study is necessary regarding need (10/28/09 Tr. 26, 98, 100-01), and their opinion should be accorded great deference, given the regional planning responsibility conferred on the ISO by FERC. Mr. Mezzanotte has testified that the system, which has recently experienced a couple of close calls,[79] is already beyond its capability to handle contingencies that must be considered under NERC, NPCC and ISO reliability standards and criteria. (10/28/09 Tr. 26) The Reliability Projects should be approved now.

IV. <u>The ISO's RSP Planning Process Is Consistent with Connecticut's IRP Process, Which Has Been Completed for 2009</u>

Critics of the GSRP have attempted in this proceeding to utilize Connecticut's IRP process as a tool to dissuade the Council from approving the GSRP. Their claims that the IRP process has not been implemented or is inconsistent with the ISO's RSP planning process are not substantiated by either fact or law. The truth is that the ISO and its regional planning process are embedded in the IRP process, and the IRP process,

[79] Mr. Mezzanotte cited, for example, the necessity of emergency actions by operators at the July, 2005 peak, when significant generation in the Springfield area was unavailable and the system was on the edge of its capability. (10/27/09 Tr. 179) He also commented that even at a relatively low load level of 18,000 MW in 2009 that generators could not have come on line quickly enough to avert an outage that could have resulted from the imminent danger of a tree taking down lines in western Massachusetts and resulting overloads on other lines. He explained that in one operational solution to this situation, every megawatt from Agawam would have to be matched by 15 megawatts in Connecticut. Thus providing 100 MW in Massachusetts would have necessitated the generation of 1,500 in Connecticut. (*Id.* at 180-81)

which began in 2008,[80] has recently completed a second full cycle, culminating in a review by the DPUC[81] which is supportive of NEEWS and its components.

The CEAB serves by statute as the state's representative in the ISO's regional planning process, and its role includes encouraging municipalities affected by proposed regional projects to participate in the ISO's RSP process.[82] Clearly, the legislature was cognizant of the ISO's role and regional planning process and intended the CEAB to be a participant in that process, not the occupant of a parallel energy world.

The CEAB's responsibilities also include review of the procurement plan submitted by the state's electric distribution companies ("EDCs") pursuant to CGS Section 16a-3a as part of the IRP process. The CEAB is required by statute to conduct its review, which may lead to approval or modification and approval, in consultation with the ISO before submitting the reviewed plan to the DPUC for final review and approval.[83] Had the legislature not intended that the CEAB act in coordination with the

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[80] *See* Decision in Docket No. 08-07-01, *DPUC Review of the Integrated Resource Plan*, September 30, 2009 (the "2008 IRP Decision"), February 18, 2009.

[81] *See* Decision in Docket No. 09-05-02, *DPUC Review of the 2009 Integrated Resource Plan*, September 30, 2009 (the "2009 IRP Decision").

[82] CGS Section 16a-3(b) provides as follows:

> (b) The board shall (1) *represent the state in regional energy system planning processes conducted by the regional independent system operator*, as defined in section 16-1; (2) *encourage* representatives from the *municipalities* that are affected by a proposed project of regional significance *to participate in regional energy system planning processes conducted by the regional independent system operator*; (3) participate in a forecast proceeding conducted pursuant to subsection (a) of section 16-50r; (4) participate in a life-cycle proceeding conducted pursuant to subsection (b) of section 16-50r; and (5) *review the procurement plan submitted by the electric distribution companies pursuant to section 16a-3a. (emphasis added)*

[83] CGS Section 16a-3a(e) provides in pertinent part as follows:

> (e) The board, *in consultation with the regional independent system operator*, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than … sixty days after receipt. … The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The

ISO, it would not have required such consultation as part of the IRP process. Under CGS Section 16a-3b, the DPUC has oversight responsibility for implementation of the approved plan, and the EDCs have the responsibility to seek approvals from appropriate regulatory agencies for transmission upgrades envisioned by the plan, as CL&P is doing through its Application to the Council in this proceeding.

It is clear that the IRP process has been followed in 2009 and that it contemplates the GSRP project and other components of NEEWS. Such a conclusion is irrefutably supported by the DPUC's Decision (the " 2009 IRP Decision") in Docket 09-05-02 (the "IRP Docket").[84] Mr. Peaco, who acted as the CEAB's consultant with respect to the IRP process and plan review, testified on behalf of the CEAB as to the steps entailed in the IRP process, essentially acknowledging that they had been followed and had led to the 2009 IRP Decision. (11/4/09 Tr. 182) He confirmed that he had indeed consulted with the ISO regarding the IRP submitted by the EDCs and that such discussions included the GSRP. (*Id.* at 187) Mr. Peaco, who participated in the IRP Docket, agreed that the DPUC considered transmission in its 2009 IRP plan approval. (*Id.* at 188) It is quite apparent from the IRP Decision itself that such consideration, including explicit discussion of NEEWS and its components, as well as DPUC knowledge of the CEAB's evaluation of competing generation alternatives, was not casual. The DPUC, noting the CEAB's

> department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. ... For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission. (*emphasis added*)

See also, 2009 IRP Decision, p. 3

[84] Whether either the CEAB or NRG agrees with the DPUC IRP Decision is not the test of whether the IRP process has been adhered to in 2009. It is clear from the IRP Decision that the process has been followed and completed in 2009 and that other Connecticut regulatory agencies may therefore act accordingly.

criticisms regarding transmission and the analysis of non-transmission alternatives,[85] recognized the need for the GSRP, the intended coordination of the IRP process with the ISO's planning process, and the failure of any party to present non-transmission alternatives in either process.[86]

The CEAB's reservations regarding the GSRP, as expressed in the IRP Docket through a CEAB report dated May 1, 2009, were based on its belief that the ISO was still considering, through an updated re-evaluation of reliability needs, whether the GSRP was needed.[87] The CEAB believed it premature to conclude there were no practical alternatives to the GSRP before the ISO completed its re-evaluation.[88] Thereafter, on approximately May 19, 2009, the ISO completed its updated review of the Needs Assessment and concluded that the need for the GSRP had not changed and that the project should not be deferred.[89] Consequently, the basis for the CEAB's reservations regarding the GSRP has been removed.

Mr. Peaco, who has attended the ISO's PAC meetings on behalf of the CEAB, including meetings related to the GSRP, commented on the need for coordination

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[85] It deserves mention that the DPUC, in commenting on the CEAB's position regarding the analysis of non-transmission alternatives, said, "The CEAB noted that the analysis should address alternatives to transmission that *meet the same needs, including reliability*." (*emphasis added*) DPUC IRP Decision, p.10.

[86] *Ibid.*; regarding the consideration of alternatives, the DPUC also made the following observation, noting that participants failed to present alternatives in either the ISO's RSP process or the IRP process:

> NRG and other docket participants had ample opportunity to present non-transmission alternatives as part of the ISO New England Regional Planning process and in this IRP process and failed to present any such alternatives. Therefore, any suggestion that the Department failed to meet its statutory obligations to consider alternatives is incorrect.

[87] *Id.* at p. 6.

[88] *Id.* at pp. 6-7; (11/4/09 Tr. 184-85).

[89] ISO Ex. 3, ISO Supplemental Response to OCC interrogatories, Question 16.

between the ISO planning process and the IRP, even stating that action at the IRP planning had to be integrated with action at the ISO level. (11/4/09 Tr. 189, 194)

While there are differences between the ISO planning process and the IRP process, they share the same fundamental goal of providing reliable electricity in a cost-effective manner. Both processes seek to identify and meet needs and both are conducted in open fashion that invites input from interested parties and stakeholders. Both processes result in an annual plan which provides for readjustment as needs change. Both processes welcome a mix of resources to meet identified needs, and the priority accorded to market solutions, including generation, demand response and conservation, in the ISO process is intended to allow market efficiencies to generate cost reductions. The two processes are compatible and should not be pitted against each other, especially when the power system is at risk.

It bears mention that while the ISO's responsibilities assuredly run to the regional power system and to resolving identified needs on a basis which makes sense from a regional perspective, that does not mean that the ISO therefore intentionally seeks solutions which are "regional" in the sense of straddling state lines rather than "state" solutions which are confined within one state's boundaries. (10/28/09 Tr. 80, 91, 222) Instead, absent sufficient market solutions, the ISO looks for an appropriate, efficient, cost-effective electrical solution which can be regionalized in terms of cost, regardless of where needed facilities are located. (*Id.* at 91) In prior cases involving Connecticut, for example, the appropriate "regional" solution involved facilities located entirely within Connecticut, such as the Bethel-Norwalk line[90] and the Middletown-Norwalk line.[91] The

[90] CSC Admin. Notice Item 47, Connecticut Siting Council Docket No. 217.

GSRP is the first instance where facilities happen to straddle Connecticut's border, but they resolve reliability problems on both sides of the state line.

It is possible, as Mr. Kowalski testified, that separate solutions could be developed for Connecticut and Massachusetts, instead of pursuing the GSRP. (10/28/09 Tr. 87) However, such a course of action would necessitate both more construction and more money and would result in less reliability. (*Id.* at 19-20, 87-88) Furthermore, if facilities involved in separate state solutions were deemed not to provide regional benefits, they would not qualify as Pool Transmission Facilities ("PTF") whose cost could be spread across the New England. (10/27/09 Tr. 153-54) Instead, such cost would be borne entirely within the state where such facilities were constructed. (10/28/09 Tr. 21-22) Even if a project did qualify as PTF, the ISO would not allocate the excess cost of a solution which cost more than necessary to accomplish the desired system benefit to other states in New England. (10/27/09 Tr. 153-54) Connecticut's share of any project which qualifies as PTF and whose cost is fully allocated across the New England region is approximately 27%, so the state benefits from regional projects. (10/28/09 Tr. 189-90)

The intended consistency between the IRP process and the ISO's planning process is underscored by the CEAB's role with respect to the Reactive RFP process,[92] which has brought NRG's proposed Meriden plant into this proceeding. It is a key legislative precept of the reactive RFP process that alternative solutions submitted in response to such an RFP shall be evaluated by the CEAB in accordance with infrastructure criteria guidelines consistent with "national and regional reliability criteria applicable to the regional transmission power grid, as determined in consultation with the

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[91] CSC Admin. Notice Item 45, Connecticut Siting Council Docket No. 272.
[92] *See* CGS Sections 16a-7c, 16-50i and 16-50*l*(e).

[ISO].”[93] Again, had the legislature not intended the CEAB to act in coordination with the ISO, there would have been no statutory mandate of consistency with national and regional reliability criteria and no statutory requirement for consultation with the ISO in that regard. Mr. Peaco acknowledged that the CEAB is required to make sure that its infrastructure criteria guidelines are consistent with national and regional reliability standards. (11/4/09 Tr. 192)[94]

As Mr. Peaco readily agreed, although the IRP and RSP study processes are ongoing, at some point it is necessary to act upon the existing body of knowledge rather than permitting one process to halt progress under the other. (11/4/09 Tr. 190) Mr. Rourke indicates that the time to act has arrived:

> We've seen problems in the Springfield area for years now. We've had two of the key generators in Springfield actually ask to leave the market over the last four, five, six years or so. We've had to put reliability agreements in place to retain those units without market compensation due to the problems that we've seen in the area. And so -- you know, the needs are right now. (10/28/09 Tr. 100)

CONCLUSION

The ISO firmly believes that there is a compelling public need for the GSRP and the MMP and that a Certificate of Environmental Compatibility and Public Need should be granted to allow the Applicant to construct the Connecticut-based facilities which are part of these Reliability Projects as proposed in the Application.

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[93] CGS Section 16a-7b(a)(6)

[94] Mr. Peaco also acknowledged, with respect to CEAB's evaluation of the proposed Meriden generating plant as an alternative to the GSRP, that the CEAB had not modeled load flows with respect to the Meriden plant and did not make a determination that the Meriden proposal would meet national and regional reliability standards. (11/4/09 Tr. 192)

Respectfully submitted,

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By ______________________

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CERTIFICATION

I hereby certify that a copy of the foregoing was hand delivered or sent via email or first class mail, postage prepaid, on January 15, 2010 to all parties and intervenors of record as shown on the attached service list.

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Anthony M. Macleod
Commissioner of the Superior Court