Decision and Orders

Massachusetts Energy Facilities Siting Council

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Bay State Gas Company for Approval of its Application to Construct an 18.2-Mile, 16-Inch Diameter, Natural Gas Pipeline with a Maximum Operating Pressure of 500 Pounds Per Square Inch and Ancillary Facilities Thereto	)	EFSC 89-13

FINAL DECISION

Stephen Klionsky
Hearing Officer
October 12, 1990

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The Energy Facilities Siting Council ("Siting Council") hereby CONDITIONALLY APPROVES the petition of the Bay State Gas Company to construct an 18.2-mile, 16-inch diameter, natural gas pipeline, with a maximum operating pressure of 500 pounds per square inch, and ancillary facilities thereto, in the City of Springfield and in the Towns of Monson, Palmer, Wilbraham and Ludlow.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

The Bay State Gas Company ("Bay State" or "Company") has proposed to construct an approximately 18.2-mile, 16-inch diameter, 500 pounds per square inch ("psi") gas distribution main from the Tennessee Gas Pipeline Company's ("Tennessee") interstate gas pipeline in Monson, through Palmer, Wilbraham and Ludlow, to the proposed MASSPOWER cogeneration facility ("MASSPOWER") on the property of the Monsanto Chemical Company ("Monsanto") in Springfield. The Company proposed an alternative route beginning at Tennessee's interstate gas pipeline in Hampden, then running through Wilbraham and Ludlow to the proposed MASSPOWER facility in Springfield. The pipeline along this route also would be 16 inches in diameter and have a maximum pressure of 500 psi; an eight-inch, 500 psi pipeline would extend from from this pipeline to the towns of Monson and Palmer (Company Brief, p. 2). The Company's submittal also included several variations from the proposed and alternative routes.[1]

Bay State is the second largest local gas distribution company ("LDC") in Massachusetts, serving 58 communities in its Brockton, Lawrence and Springfield divisions. In the twelve months ending October 31, 1988, the Company served an average of 217,572 on-system firm service customers, consisting of 149,116 residential customers, 48,603 residential non-heating customers, 19,115 commercial customers, and 738 industrial customers. Bay

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1/ A complete description of the proposed and alternative routes and all variations is provided in Section III.B, below.

State also makes firm sales to off-system customers and sells gas to interruptible customers. Bay State Gas Company, 19 DOMSC 140, 145 (1989) ("1989 Bay State Decision").[2]

Bay State receives pipeline gas and underground storage return gas from Tennessee at Bay State's Agawam, Northampton, East Longmeadow, Lawrence, Brockton, Mendon, Mahwah and Taunton gate stations for delivery to its three divisions.[3] The Company also receives pipeline gas and underground storage return gas from Algonquin Gas Transmission Company ("Algonquin") through take stations located in Massachusetts for its Brockton division. In addition, Bay State has auxiliary liquefied natural gas ("LNG") facilities in Massachusetts and Rhode Island and auxiliary propane facilities in Massachusetts. Finally, the Company leases LNG storage and vaporization facilities from Providence Gas Company and Industrial National Leasing Company. Id. at 146.

In the 1989 Bay State Decision, the most recent Siting Council review of Bay State, the Siting Council approved the sendout forecast and supply plan of the Company. Id. at 238-239.

B. Procedural History

In September 1988, Bay State requested that the Siting Council approve the Company's sendout forecast and supply plan and the Company's proposal to construct a 19-mile high pressure gas pipeline. The petition was docketed as EFSC 88-13. The high-pressure gas main as proposed in September 1988 would have interconnected with Tennessee's interstate pipeline in Monson, would have proceeded along public ways through the towns of

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2/ Off-system customers purchase gas for resale outside Bay State's service territory. The Company's off-system customers are both Massachusetts and non-Massachusetts LDC's (1989 Bay State Decision, 19 DOMSC at 145, n.4).

3/ Bay State's Tennessee volumes are delivered to Granite State Gas Transmission, Inc. ("Granite State"), a wholly-owned subsidiary of Bay State, which, in turn, delivers the volumes to Bay State. Each of the contracts Bay State had previously entered into with Tennessee for pipeline gas and underground storage return have been assigned to Granite State. Id. at 146 (citing Bay State Gas Company, 16 DOMSC 283, 287 n.6 (1987)).

Monson, Palmer, Wilbraham, and Ludlow and would have terminated at Massachusetts Municipal Wholesale Electric Company's ("MMWEC") Stony Brook Energy Center ("SBEC") facility in Ludlow (hereinafter, solely for purposes of this procedural summary, this will be referred to as the "MMWEC line"). The Siting Council held public hearings on the sendout forecast, supply plan and the proposed MMWEC line on October 26, 1988 in Wilbraham, and on October 27, 1988 in Palmer.

In December 1988, the Company amended the portion of its application relating to the MMWEC line and, after appropriate legal notice, additional hearings on the proposal were held on March 1, 1989 in Ludlow and on March 2, 1989 in Monson. Subsequently, on March 23, 1989, the Company submitted to the Siting Council an additional application seeking approval to construct a high-pressure gas pipeline branching off the proposed MMWEC line and terminating at the proposed MASSPOWER cogeneration facility in Springfield (hereinafter this line will be referred to as the "MASSPOWER line"). This additional application was docketed as EFSC 89-13.

On June 8, 1989, Bay State submitted further motions concerning the pipeline route. These motions sought, in part, to consolidate in one proceeding all facility proposals. On July 10, 1989, the Hearing Officer granted Bay State's motions to sever its September 1988 forecast and supply plan application (which would continue as EFSC 88-13) from any facility proposal, as well as its motion to consolidate the two facility proposals as EFSC 89-13. All parties that had intervened in EFSC 88-13 were deemed to be parties to both EFSC 88-13 and EFSC 89-13.[4]

On August 18, 1989, the Company moved to amend its consolidated facilities application in EFSC 89-13 to "remove that portion of the facility which would be used...to serve MMWEC." In addition, on November 10, 1989, the Company requested what was termed a "minor amendment" in the proposed pipeline route. The proposed route changes were ruled on on

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4/ Subsequently, on November 12, 1989, Louisa May and Philip W. Bouchard, and Chester Clark, intervenors in EFSC 88-13, withdrew as intervenors in EFSC 89-13.

November 30, 1989 (see 1989 Bay State Decision, 19 DOMSC at 148, n.8)[5] and reflected in the revised route set forth in the legal notice issued November 15, 1989. Pursuant to this notice, a public hearing was held on the revised pipeline proposal on December 12, 1989 in Ludlow.

The Siting Council held evidentiary hearings in its offices on this matter on April 24, 26, 30, May 3, and May 14, 1990. The Company presented five witnesses: Charles G. Setian, senior vice president, who provided an overview of the project and the Company's site selection process; Paul W. LaShoto, assistant vice president, who testified on the planned construction techniques, pipeline safety, environmental impacts and compliance with environmental protection requirements; George M. Long, assistant director of industrial education for distribution at the Institute of Gas Technology, who testified on the safety of the proposed pipeline design and construction techniques; James A. Kekeisen, with J. Makowski Associates, Inc.'s Gas Development Group, who testified in regard to the gas supplies to be transported over the proposed pipeline to MASSPOWER; Charles T. Ellis, senior vice president of gas supply for the Company, who testified on the evolution of the proposed project, the gas supply contract with MASSPOWER, and discussions held with MMWEC concerning the supply of gas to MMWEC.

MMWEC initially submitted prefiled written testimony, but pursuant to a joint motion and stipulation agreed to by Bay State and MMWEC, dated May 25, 1990, MMWEC agreed to withdraw this testimony and generally to withdraw from further participation in the proceeding. This joint motion and stipulation was agreed to by the Hearing Officer on May 30, 1990.

The Hearing Officer entered 150 exhibits into the record, largely composed of Bay State's responses to information and record requests. Seven of the Company's exhibits were entered as were 31 of MMWEC's exhibits. In addition, the record of the 1989 Bay State Decision was incorporated into the record of

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5/ As indicated above, on November 30, 1989, the Siting Council issued the 1989 Bay State Decision, approving the Company's forecast and supply plan.

this proceeding (see Tr. I, p. 14).

On June 29, 1990, Bay State and MASSPOWER filed briefs. MMWEC filed written comments on July 13, 1990.

C. Jurisdiction

The Company's petition to construct an 18.2-mile, 500 psi, natural gas pipeline and ancillary facilities is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, which requires gas companies to obtain Siting Council approval for construction of a facility at a site before a construction permit may be issued by any other state or local agency.

The Company's proposal to construct an 18.2-mile pipeline operating at a pressure of up to 500 psi falls squarely within the fifth definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (5) any new pipeline for the transmission of gas having a normal operating pressure in excess of one hundred pounds per square inch gauge which is greater than one mile in length except restructuring, rebuilding, or relaying of existing transmission lines of the same capacity.

The Company's proposal to construct the related gas pipeline at a pressure of less than 100 psi falls squarely within the third definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility.

In addition, the Siting Council previously established a two-part standard for determining whether a structure is a facility in Commonwealth Electric Company (17 DOMSC 249, 263 (1988) ("1988 ComElectric Decision")). In that case, the Siting

Council stated that a structure is a facility under G.L. c. 164, sec. 69G, if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility (id., see also Berkshire Gas Company, EFSC 89-29 (Phase II) (1990), p. 9). The additional length of pipeline here is subordinate to the proposed pipeline, and provides no benefit outside of its relationship to the proposed facility.

Accordingly, in accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section II.A, below). Second, the Siting Council requires the applicant to establish that its project is superior to alternative approaches in terms of cost, environmental impact, reliability and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Council requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, and that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impacts, and reliability of supply (see Section III, below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources to meet reliability or economic efficiency objectives.[6] The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated the reliability of supply systems in the event of changes in demand or supply or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Council has found that new capacity is needed where projected future capacity available to the system is found to be inadequate to satisfy projected load and reserve requirements. MASSPOWER Decision, EFSC 89-100 (1990), p. 32; Altresco-Pittsfield, Inc., 17 DOMSC at 369; Northeast Energy Associates, 16 DOMSC 335, 360 (1987) ("NEA"); Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986) ("1986 CELCo Decision"); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"); New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Council has found that new capacity

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6/ In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions including, but not limited to, gas transmission lines, synthetic natural gas facilities, liquefied natural gas facilities, propane facilities, gas storage facilities, energy or capacity associated with gas sales agreements, and energy or capacity associated with conservation and load management.

is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("Middleborough"); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982) ("Taunton"); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984) ("1984 Boston Gas Decision").

While G.L. c. 164, sec. 69H, requires the Siting Council to ensure an adequate supply of energy for Massachusetts, the Siting Council has interpreted this mandate to encompass not only evaluations of specific need within Massachusetts for new energy resources (Massachusetts Electric Company and New England Power Company, 18 DOMSC 383, 396-403 (1989) ("1989 NEPCo Decision"); Commonwealth Electric Company, 17 DOMSC 249, 266-279 (1988) ("1988 CELCo Decision"); Middleborough, 17 DOMSC at 216-219; 1985 BECo Decision, 13 DOMSC at 70-73), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Turners Falls Limited Partnership, 18 DOMSC 141, 151-165 (1988) ("Turners Falls"); Altresco Decision, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-354; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo Decision, 13 DOMSC at 129-131, 133, 138, 141. In so doing, the Siting Council has fulfilled the requirements of G.L. c. 164, sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region's and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in the New England

Power Pool ("NEPOOL").

Here, the Siting Council is presented with a proposal by a gas utility to construct a jurisdictional gas pipeline that would primarily transport gas to a cogeneration plant constructed by a non-utility developer. Significantly, the pipeline would also provide gas service to areas within the Company's expanded service territory.[7, 8] Therefore, the Siting Council must evaluate the need for additional energy resources based on both goals of the proposed project. The proposal to construct the cogeneration plant has been conditionally approved by the Siting Council (MASSPOWER Decision, EFSC 89-100 (1990). Additionally, the Company's most recent sendout forecast, which included forecasted loads specific to the new areas to be served by the proposed pipeline, also has been approved by the Siting Council (1990 Bay State Decision, 19 DOMSC at 140).

The Siting Council previously has approved a proposal by a gas utility to construct a jurisdictional gas pipeline that would provide fuel transportation for a cogeneration plant developed by a non-utility entity. 1990 Berkshire Gas Decision, EFSC 89-29 (Phase II). The Siting Council also previously has approved a proposal by a gas utility to construct a jurisdictional gas pipeline that would provide a new fuel source to an existing generating plant owned by an electric utility. 1984 Boston Gas Decision, 11 DOMSC at 159. Further, the Siting Council previously has reviewed proposals

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7/ The Company stated that it was reserving approximately one-sixth of the capacity of the proposed pipeline for (1) expansion of gas service into the towns of Monson and Palmer, and into areas of Wilbraham and Ludlow not currently served; and (2) future expansion into towns north of Bay State's current service territory, including Ware and Belchertown (Exhs. HO-3, HO-4; Bay State Brief, p. 15).

8/ The Company further indicated that a significant portion of the capacity of the proposed project could be used to substantially increase interruptible sales to MMWEC's Stony Brook Energy Center in Ludlow by interconnecting the proposed pipeline with the Company's existing 275 psi distribution system (Exh. HO-9; Tr. 1, pp. 80-89; Tr. 2, pp. 89, 114).

by both electric companies and non-utility developers to construct jurisdictional electric transmission lines that would connect non-jurisdictional cogeneration plants to the regional transmission system. Turners Falls, 18 DOMSC at 195-196; Massachusetts Electric Company, 18 DOMSC 383, 425 (1989).

In all such cases, whether the proponent is a utility or a non-utility developer, the proponent first must establish that the power from the cogeneration facility is needed on either reliability or economic efficiency grounds. If it can be established that the cogeneration plant is needed, the proponent then must show that the existing system is inadequate to support this new power source and that additional energy resources are necessary to accommodate the new power source. 1989 MECo Decision, 18 DOMSC at 383; Turners Falls, 18 DOMSC at 141. In applying this standard, the Siting Council has emphasized that our review of need is not limited to the need for a physical connection between the cogeneration plant and its fuel source or its end-users. To address the need issue in such cases so narrowly would be inconsistent with our need analysis for other facilities, as well as inconsistent with our statutory mandate.

The Siting Council also previously has approved a proposal by a gas company to construct a jurisdictional gas pipeline to serve load growth (Boston Gas Decision, 17 DOMSC 155 (1988)), and has approved a proposal by an electric company to construct a jurisdictional transmission line to ensure reliable supply to existing and future loads (1988 ComElectric Decision, 17 DOMSC at 249). In such cases, the proponent must establish that its existing distribution system is inadequate to satisfy expected load growth with acceptable reliability and that additional energy resources are necessary to accommodate the anticipated load growth.

2. Need for the Jurisdictional Cogeneration Plant

The Siting Council previously has found that the region needs the power from MASSPOWER and that, at such time that MASSPOWER complies with the condition regarding power sales set forth in the MASSPOWER Decision, Massachusetts stands to receive reliability and/or economic efficiency benefits from the additional energy resources produced by the MASSPOWER cogeneration plant (MASSPOWER Decision, EFSC 89-100, p. 101). Accordingly, for the purposes of this decision, the Siting Council finds that, at such time that MASSPOWER complies with the condition regarding power sales set forth in the MASSPOWER decision, the need for the additional energy resources from the MASSPOWER cogeneration plant will be established.

3. Need for Additional Pipeline Capacity

a. Standard of Review

As noted previously, Bay State proposes construction of a gas pipeline intended to (1) transport gas for a non-utility user to that user's cogeneration plant located in Bay State's service area and (2) provide service to new areas in the Company's expanded service territory. While this is the first case in which the Siting Council has reviewed a proposal that combines these two purposes, the standard of review for need as applied in previous electric transmission and gas pipeline facility cases remains essentially unchanged. In the final analysis, the need for energy resources in the form of additional pipeline capacity hinges upon the adequacy of the Company's existing system to meet its current needs, including anticipated system growth.

b. Description of the Existing System

Bay State introduces gas into its greater Springfield distribution system from two types of facilities -- Tennessee's meter delivery stations in Agawam and East Longmeadow and Bay State's LNG storage facility in Ludlow (Tr. 3, pp. 12-14).[9]

9/ The Company's Springfield Division receives gas from Tennessee at its Agawam, East Longmeadow and Northampton gate stations (see Section I.A, above). The Agawam and East Longmeadow gate stations serve the greater Springfield distribution system. The Northampton gate station serves a distribution system that is not interconnected with the greater Springfield distribution system. Therefore, gas cannot be fed from the Northampton distribution system to the greater Springfield distribution system. (Tr. 3, p. 12).

Tennessee transports gas to Bay State's greater Springfield distribution system via its main line, Tennessee's principal pipeline supplying Massachusetts. The Tennessee main line enters the Commonwealth from New York state and passes to the south of Springfield (through the towns of Agawam, Longmeadow and East Longmeadow) and continues to the east through the towns of Hampden and Monson. Bay State's greater Springfield distribution system runs north from the Tennessee gate stations (id.). The Company's maximum daily quantities ("MDQ") received at the two Tennessee meter stations are 40,000 mcf (Agawam) and 25,000 mcf (East Longmeadow) (EFSC 88-13, Exh. SP-1A).

Approximately ten miles north of the East Longmeadow gate station, the Company operates a LNG liquefaction and storage facility (id.). This facility has a storage capacity of 1020 BBtu and a maximum daily design vaporization capacity of 55 BBtu (EFSC 88-13, Exh. BSG 1, Table G-14, p. 87). Mr. Setian indicated that the Ludlow LNG facility is critical to meeting the needs of the northern part of the Company's greater Springfield distribution system (Tr. 3, pp. 13-14).

Mr. Setian stated that Bay State's distribution system currently includes a 10-inch line which serves the Monsanto complex (id., pp. 16-17). Mr. Setian further stated that the 10-inch line to Monsanto typically operates at 60 psi and is capable of carrying approximately 400 mcf per hour to the Monsanto complex (id.). The Company currently has no distribution system serving the towns of Monson or Palmer (EFSC 88-13, Exh. BSG-1, p. 101; Bay State Brief, pp. 2, 13, 24).

c. Adequacy of the Existing System to Supply MASSPOWER and Other Areas

The Siting Council previously approved the Company's supply plan, finding it adequate for the Company's projected sendout over the forecast period (1989 Bay State Decision, 19 DOMSC at 223-224). Bay State's supply plan for the combined Springfield and Lawrence divisions calls for continued use of existing resources to serve forecasted firm and interruptible loads in those divisions (id., pp. 66-80).[10] The Company stated that the distribution system in the Springfield area is adequate to meet the needs of Bay State's current customers and forecasted growth, other than increased load at MMWEC's SBEC, at MASSPOWER or increased load in new service areas without system reinforcement (Exh. HO-22). The Company further stated that the existing service to the Monsanto complex is expected to continue even after construction of the MASSPOWER project and noted that Monsanto had recently contacted Bay State regarding possible increases in the level of service for its complex (Tr. 3, pp. 17-19). Finally, the Company stated that the existing facilities which serve the Monsanto complex have very limited capacity available for additional service (id., p. 19).

The Company stated that it had executed a precedent agreement with the developers of MASSPOWER which requires each party to execute a firm gas transportation agreement upon completion of certain regulatory and financial processes (Exh. HO-10; Bay State Brief, p. 14).[11] The firm transportation agreement will require Bay State to transport 50,000 MMBtu per day (approximately 2,000 MMBtu per hour) to MASSPOWER at a delivery pressure of 340 psi for a period of 20 years (id.; Tr. 4, pp. 53-54).[12] Thus, MASSPOWER's requirements are approximately five times the capacity of the existing facilities which serve the Monsanto complex. In addition, the delivery pressure requirement of

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10/ The Company forecasts combined total sendout for the Lawrence and Springfield divisions due to the high degree of supply flexibility between the two divisions (1989 Bay State Decision, EFSC 88-13, p. 21).

11/ The Company stated that its obligations under the transportation agreement are dependent on approval of the agreement by the Massachusetts Department of Public Utilities ("MDPU"), and noted that the agreement is currently under review by that agency with a decision "expected in the near future" (Bay State Brief, p. 14).

12/ One thousand cubic feet ("mcf") of natural gas equals roughly one Dekatherm or one million Btus ("MMBtu"). For purposes of this review, the Siting Council assumes that one mcf is equivalent to one MMBtu.

340 psi is considerably greater than the existing facilities are capable of supplying.

Based on the foregoing, the Siting Council finds that the Company has established that the existing greater Springfield distribution system is inadequate to accommodate both its current and anticipated system needs, including the requirements of MASSPOWER. Accordingly, the Siting Council finds that the Company has established that there is a need for additional energy resources to meet the fuel supply requirements of MASSPOWER.

d. Adequacy of the Existing System to Supply the Expansion Areas

The Company proposes to utilize the proposed pipeline to expand service into the towns of Monson and Palmer, into areas of Wilbraham and Ludlow not currently served and, in the future, into towns to the north and east of the Company's current service territory including Ware and Belchertown (hereinafter the "expansion areas") (Exhs. HO-3, HO-4; Bay State Brief, p. 15). As noted above, the Siting Council approved the Company's most recent sendout forecast and supply plan, which included forecasted loads specific to the expansion areas to be served by the proposed pipeline (see 1989 Bay State Decision, 19 DOMSC 140).

Mr. Setian stated that the Company had been interested in bringing gas service into the Towns of Monson and Palmer for several years, but that "building a take station and extending a distribution system into Monson Center and Palmer Center was just not economical" (Tr. 1, pp. 131-132). The Company indicated that when service to these towns was considered in combination with service to a large customer such as MMWEC or MASSPOWER, the economics were significantly altered (id., p. 135; EFSC 88-13, Exhs. BSG-1, p. 102, HO-N-1). The Company stated that once such a combined approach became possible the Company requested the MDPU to allow it to serve the towns (EFSC 88-13, Exh. BSG-1, p. 102). The Company's petition to the MDPU for the right to serve the towns was granted in July 1987 (id., Appendix F & G).

The Company provided further analyses and documentation in support of its forecast of load potential in the expansion areas in this proceeding, including contracts with potential customers and inquiries regarding gas service from potential customers (Exhs. HO-1, HO-2, HO-RR-1, HO-RR-2, HO-RR-11). Specifically, the Company forecasts that in 20 years annual consumption in Monson and Palmer will reach 542,462 MMBtu (approximately 458 MMBtu per hour) (Exh. HO-RR-2). The Company did not provide specific forecasts for load potential in Ware and Belchertown, but noted that as the towns are similar in size and make-up to Monson and Palmer, a similar load potential is likely (id., Tr. 1, pp. 163-164).[13]

Based on the foregoing, the Siting Council finds that the Company has established that a legitimate load potential exists in the expansion areas which cannot be served by the existing greater Springfield distribution system. Accordingly, the Siting Council finds that the Company has established that there is a need for additional energy resources to serve load potential in the expansion areas.

e. Adequacy of the Existing System to Supply MMWEC

As previously noted, Bay State's original filing proposed direct service from the 500 psi natural gas pipeline to Ludlow to MMWEC's SBEC facility. The Company later eliminated those portions of the proposed routes which were necessary to serve the MMWEC facility from the 500 psi pipeline (see Section I.B, above). Nonetheless, the record in this case reflects considerable discussion regarding the potential to

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13/ Mr. Setian indicated that the load potential in the expansion areas would be accessible from either the proposed or alternate routes, but noted that the rate of attachment, as well as some of the specific loads attached would likely vary (Tr. 1, pp. 68, 167-169). Mr. Setian further stated that the Company had made a commitment to serve the Palmer Industrial Park, and that this load likely would be served within one year of the completion of construction of either the primary or alternative route (id.; Exh. HO-RR-3).

utilize the proposed pipeline line to increase gas sales to SBEC.[14] Subsequent to this discussion, the Company and MMWEC entered into a stipulation in this proceeding, dated May 25, 1990, which was accepted by the Hearing Officer on May 30, 1990, and which states, in part, that it is not relevant and not an issue in this proceeding whether the 500 psi pipeline, in conjunction with another high pressure pipeline not-as-yet proposed or constructed, could meet the SBEC's volume and pressure requirements.[15]

Accordingly, the issue of whether the proposed 500 psi pipeline, in combination with a not-yet-constructed high pressure connecting line, could meet the needs of SBEC, is not an issue in this proceeding.

While the sufficiency of a direct link of SBEC to a 500 psi line is not relevant here, the Company has raised a somewhat different issue. That is, whether MMWEC's SBEC facility needs additional natural gas that could be supplied to MMWEC through interconnecting the proposed 500 psi project with

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14/ The Company indicated that there remains the possibility that the proposed 500 psi line would be extended to SBEC as a means of providing expanded service at high pressure to MMWEC. However, the Company noted that any such extension would be longer than one mile and therefore would require Siting Council approval (Tr. 1, p. 64; Tr. 2, p. 190).

15/ The stipulated language reads, in part, as follows:

> It is not relevant and not an issue in this proceeding, and the EFSC staff shall make no determination, finding, ruling and/or order on whether Bay State's proposed high-pressure 16-inch gas pipeline in conjunction with any additional high-pressure gas pipeline not currently constructed or in service, or high pressure service line not currently constructed or in service, located at some point on Bay State's proposed high-pressure 16-inch gas pipeline, could serve or meet MMWEC's SBEC facility's requirements of volumes and pressures of natural gas at least cost and with a minimum impact on the environment.

the existing 275 psi distribution system in Ludlow.[16]

The Company asserted that, historically, it has used the 275 psi distribution system in Ludlow to deliver sufficient gas to the SBEC during the period April through October to fuel two of MMWEC's three combustion turbines (Tr. 1, pp. 132, 147; Tr. 2, p. 187).[17] The Company contends that even without a direct high-pressure pipeline to SBEC, the interconnection of the proposed pipeline with the 275 psi distribution system in Ludlow would enable Bay State to supply MMWEC with sufficient volumes to operate all three turbines at SBEC all year (Bay State Brief, p. 19, Tr. 1; p. 64, Tr. 2; p. 188).[18]

Bay State contends that increased interruptible sales to MMWEC would provide significant benefits to the Company's firm service customers under any of the various scenarios of service (Exh. HO-9; Tr. 2, pp. 183-189; Bay State Brief, p. 19). Therefore, Bay State asserts that increased interruptible sales to MMWEC "make up a significant portion of the need for the proposed gas main" (Bay State Brief, p. 19).

MMWEC argues that Bay State's assertions regarding the potential to significantly increase sales to MMWEC have not

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16/ The Company stated that, in any case, it intends to interconnect the proposed pipeline with its 12-inch, 275 psi distribution system in Ludlow as a means of providing increased reliability to the northern portions of its greater Springfield distribution system in Ludlow (Exh. HO-9). The Company also noted that such an interconnection also would increase the efficiency of operation at the Company's Ludlow LNG facility (id.). For an analysis of the benefits associated with the project approach chosen by the Company, see Section II.B, below.

17/ Because of the relatively low pressure at which this gas is delivered, MMWEC must compress the gas to a higher pressure before the gas can be fed to the turbines. If the pipeline supplying MMWEC were to operate at a sufficiently high pressure, no compression would be necessary, and the costs associated with compression would be avoided (Tr.1, pp. 64, 89-90).

18/ Mr. Setian stated that the capacity of the 275 psi distribution system has limited the amount of natural gas that could be provided to SBEC. He also stated that with an interconnection, as set forth above, there would be a significant increase in the amount of gas that could be delivered to SBEC (Tr. 3, pp. 7-8).

been substantiated on the record in this proceeding (MMWEC Comments, p. 2). MMWEC further argues that Bay State's forecast of increased sales to MMWEC does not take into consideration the price at which the interruptible supplies would be offered to MMWEC, and therefore cannot be relied upon (id., pp. 3-4).

In the 1989 Bay State Decision, the Siting Council accepted, for the purposes of the Company's sendout forecast, a forecast that interruptible sales to MMWEC would increase. In that decision, the Siting Council stated that, because the interruptible market was to be served largely from spot purchases, "the inability to sell gas in the forecasted amounts to a specific customer should not have an unacceptable impact on the costs of the Company's supply plan" (19 DOMSC at 178). Given the acceptance of the forecast of interruptible sales in the sendout forecast, had MMWEC in this case acknowledged its interest and need for additional interruptible gas supplies, a strong case would have been made that additional supplies to SBEC were needed.

MMWEC, however, has not acknowledged that need. While the Company has stated that it is reasonable to assume that increased sales to MMWEC would come about as a result of the interconnection of the proposed 500 psi pipeline with the 275 psi distribution system (Tr. 2, pp. 183-188), MMWEC has raised substantial questions as to whether, or in what magnitude, such increased sales will come to fruition. When the claimed recipient of these additional supplies states its strong doubts concerning the likelihood of purchasing increased supplies, the project proponent has a much more difficult case to make to demonstrate need. On this record, such a demonstration has not been made.

Finally, Bay State has argued that increased sales to MMWEC provide a direct cost benefit to its firm customers. That may well be true but the profitability of potential sales do not establish a need for the additional energy resources for the purposes of this analysis.

Accordingly, the Siting Council declines to find that there is a need for additional energy resources to serve MMWEC's SBEC facility.

4. Conclusions on Need

The Siting Council has found that, at such time that the proponents of MASSPOWER comply with the conditions regarding power sales set forth in the MASSPOWER decision, the need for the additional energy resources from the MASSPOWER cogeneration plant will be established. The Siting Council also has: (1) found that the Company has established that there is a need for additional energy resources to meet the fuel supply requirements of the MASSPOWER facility; (2) found that the Company has established that there is a need for additional energy resources to serve load potential in the expansion areas; and (3) declined to find that there is a need for additional energy resources to meet the fuel supply requirements of the SBEC.

Accordingly, the Siting Council finds that (1) there is a need for additional energy resources to serve load potential in the expansion areas, and (2) at such time that MASSPOWER complies with the condition regarding power sales set forth in the MASSPOWER decision, there will be a need for additional energy resources to meet the fuel supply requirements of the MASSPOWER facility.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and

(c) no additional electrical power or gas.[19]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Turners Falls Decision, 18 DOMSC at 171-172; 1988 Braintree Decision, 18 DOMSC 1, 27 (1988); 1988 CELCo Decision, 17 DOMSC at 279-288; Middleborough Decision, 17 DOMSC at 219-225; 1986 CELCo Decision, 15 DOMSC at 212-218; 1985 MECo Decision, 13 DOMSC at 141-183; 1985 BECo Decision, 13 DOMSC at 67-68, 73-74. The Siting Council also has considered reliability impacts in comparing proposed and alternative project approaches.[20] BECo/MWRA, EFSC 89-12A at 13-14 (1989); 1989 MECo Decision, 18 DOMSC at 404-405, 410-412.

2. Project Approaches

The Siting Council considers two project approaches for meeting the identified needs for additional energy resources: (1) the Company's proposed project approach, and (2) a two pipeline or "classic" approach.

a. Bay State's Proposed Project Approach

The Company's proposed project approach consists of: (1) construction of a proposed meter station along the Tennessee main line in the Town of Monson to receive gas on behalf of

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19/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations."

20/ In the 1989 MECo Decision, the Siting Council stated that in future facility proposal reviews, we would require a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to alternative approaches (18 DOMSC at 412). The Siting Council recognizes that gas facility proposals differ significantly from electric facility proposals with respect to issues of reliability, and that a comparison of the reliability of alternative project approaches generally will not be applicable in gas facility reviews. The Siting Council does not analyze project level differences in reliability in the instant review.

MASSPOWER and Bay State, and (2) construction of the proposed 18.2-mile, 16-inch, 500 psi natural gas pipeline from the meter station through the Towns of Monson, Palmer, Wilbraham and Ludlow to the MASSPOWER facility in Springfield.[21] Also included within the Company's project approach is an alternate route and variations on both the primary and alternative routes.[22]

The Company stated that its proposed project approach will meet the identified project needs. The Company stated that this approach will enable the Company to provide MASSPOWER with firm transportation of up to 2,000 MMBtu per hour to supply its cogeneration facility, and will enable the Company to supply at least 1,000 MMBtu per hour to the geographic areas into which service is being expanded or may be expanded. The Company noted that the total capacity of the pipeline when operated at 500 psi would be 6,000 MMBtu.

According to Bay State, this approach also would enable the Company to interconnect the proposed pipeline with the Company's 12-inch, 275 psi distribution system in Ludlow (Exh. HO-9; Bay State Brief, pp. 2-3). The Company stated that, as a result of such an interconnect, the proposed project

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21/ In September 1987 the MDPU granted the Company's petition for approval of exceptions to the provisions of the Massachusetts Gas Distribution Code ("MGDC"), 220 CMR 101.06(10) and (11). The MGDC limits the operating pressure of gas pipelines to 200 psi when installed on or across bridges and under highways, except when crossing highways (EFSC 88-13, Exh. BSG-1, p. 103, Appendix H). The MDPU decision allows the Company to operate its proposed pipeline at pressures up to 500 psi.

22/ The Company's alternative proposal, as set forth in other sections of this decision, consists of construction of the meter station in the Town of Hampden, construction of an 18-mile, 16-inch, 500 psi pipeline through the Towns of Hampden, Wilbraham and Ludlow to the MASSPOWER facility in Springfield, and construction of an 11-mile, 8-inch, 500 psi pipeline from the 16-inch pipeline in Wilbraham to serve the Towns of Monson and Palmer (Exh. BSG-1, Schedule BSG 1-1; Tr. 3, p. 55). For a complete discussion and analysis of the Company's alternative route, see Section III, below.

would provide significant economic and operating efficiency benefits to Bay State's existing system and to its customers (Exh. HO-9; EFSC 88-13, Exh. HO-N-1).[23] The Company identified the added benefits of the interconnect as: (1) improving system reliability by providing reinforcement to the northern portion of the Company's greater Springfield distribution system;[24] (2) increasing the efficiency of liquefaction of the Ludlow LNG facility due to the increased pressure that could be delivered to the facility; and (3) potentially reducing the distance Tennessee must backhaul new Bay State gas supplies from eastern Massachusetts, thus reducing Bay State's transportation payments to Tennessee (Exh. HO-9; Tr. 2, pp. 205-211; Tr. 3, pp. 15, 119, 123; EFSC 88-13, Exh. HO-N-1; Bay State Brief, p. 20).

In addition, Bay State asserted that the interconnect with the 12-inch, 275 psi Ludlow distribution system would allow for a potentially significant increase in the level of interruptible sales to MMWEC's SBEC facility or service to other large loads (Exh. HO-9; Tr. 2, pp. 205-211). The Company contends that increased interruptible sales to MMWEC's SBEC as a result of the interconnection could potentially reach at least 2.5 million MMBtu per year (Exhs. HO-9, HO-17; Tr. 2,

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23/ The Company noted that either a 16-inch pipeline operated at 400 psi or a 14-inch pipeline operated at 500 psi would be sufficient to meet the needs of the MASSPOWER facility and the load in the expansion areas (Exh. HO-20). The Company stated, however, that such a reduced pressure pipeline would reduce significantly or eliminate completely the economic and operational benefits associated with the interconnection of the proposed project with the existing 12-inch, 275 psi distribution system in Ludlow (Exh. HO-20; Tr. 2, pp. 205-211).

24/ The Company stated that its system reliability improves because the proposed project approach enables it to feed the existing system from the proposed pipeline in the event of a failure at either the Agawam or East Longmeadow gate stations or the Ludlow LNG facility (Tr. 2, pp. 206-207; Tr. 3, p. 123; Bay State Brief, p. 20). The Company did not indicate whether there was a history of failures at any of these facilities.

pp. 183-189). Bay State stated that such an increase in sales would result in an annual benefit to firm ratepayers of between $625,000 and $1,250,000 (id.). The Company noted that such benefits significantly overshadow the one-time capital investment of $250,000 necessary to make the interconnection (id.). The Company also stated that other potential large loads might develop in the future which could be served by the proposed pipeline. Specifically, Mr. Setian stated that potential cogeneration hosts exist in the Town of Ware (Tr. 1, pp. 150-151).

The Company also stated that other economic benefits would flow to its firm ratepayers as a result of the revenues generated through the MASSPOWER contract and the addition of customers in the expansion areas (Tr. 2, pp. 145-146).[25]

Finally, Mr. Ellis stated that the Company would receive additional benefits from its relationship with MASSPOWER (1) through the purchase of MASSPOWER's gas supplies during periods when the MASSPOWER facility was off-line as a result of maintenance or dispatch practices, and (2) potentially, by providing MASSPOWER with interruptible supplies of gas in the event that MASSPOWER suffered an interruption in its firm gas

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25/ Mr. Ellis stated that the Company's firm transportation contract with MASSPOWER will result in a consistent annual revenue stream once the MASSPOWER facility is in operation (Tr. 2, pp. 157-160). The Company stated that, based on a project cost of $9,429,000 and annual operating and maintenance expenses of $260,000 (which represent the Company's estimate of the costs of the primary route), the revenue stream from the MASSPOWER transportation contract would result in a net annual benefit to firm ratepayers of $857,000 (Exh. HO-9). The Company also stated, however, that if the alternative route were constructed, and construction costs exceeded $13,417,000, the revenues generated by the MASSPOWER transportation contract would be insufficient to completely cover all project costs and, therefore, no net benefits would flow to the Company's firm ratepayers from the MASSPOWER contract (Exh. HO-RR-9). The Company did not quantify the annual benefits to its firm ratepayers from the addition of customers in the expansion areas, but noted that the total cost of gas is reduced by spreading the fixed costs of service over the greatest number of customers (EFSC 88-13, Exh. HO-N-1).

supply (Tr. 2, pp. 168-174).[26, 27]

b. Classic Two Pipeline Approach

The Company stated that the classic two pipeline approach to serving the needs of MASSPOWER and the Towns of Monson and Palmer would consist of (1) construction of a meter station and dedicated pipeline from the Tennessee main line to the MASSPOWER facility, and (2) construction of a separate meter station and dedicated pipeline distribution system from the Tennessee main line in Monson to the town centers of Monson and Palmer (Exhs. BSG-1, pp. 14-15; HO-12).

i. Dedicated Pipeline to MASSPOWER

The Company and MASSPOWER identified several options for serving the MASSPOWER facility with a dedicated pipeline, including: (1) a Bay State-owned, 16-inch, 500 psi pipeline along a new right-of-way ("Bay State ROW approach"); (2) a Bay State-owned, 16-inch, 500 psi pipeline along a combination of a new right-of-way and the Massachusetts Turnpike Authority ("MTA") right-of-way ("Bay State ROW/MTA approach"); (3) a

26/ Mr. Ellis stated that the MASSPOWER contract with ProGas Limited for gas supplies includes a requirement for a minimum 75 percent take by MASSPOWER. Mr. Ellis stated that, in the event that MASSPOWER cannot utilize the minimum 75 percent during a given period, the contract provides for the delivery of the balance of the minimum supplies (75 percent minus any amount MASSPOWER takes) to Granite State for transfer to Bay State. The Company stated that the cost to Bay State for these supplies would be considerably lower than the cost of traditional supplemental supplies during the winter months, and would be comparable to the cost of spot gas during the summer months (Tr. 2, pp. 170-172; Exh. HO-RR-8).

27/ Mr. Kekeisen stated that the Company and MASSPOWER had signed a precedent agreement regarding an interruptible sales contract between Bay State and MASSPOWER (Tr. 4, pp. 81-84). Mr. Ellis stated that such a contract likely would be executed in the event that MASSPOWER's firm gas supply arrangements were delayed (Tr. 2, pp. 168-170). The Company noted that such a contract would need MDPU approval before it could become effective (Exh. HO-RR-8).

Tennessee-owned, 12.75-inch, 877 psi pipeline along a new right-of-way ("Tennessee ROW approach");[28] and (4) a Bay State-owned 16-inch, 500 psi pipeline along a public way ("Bay State MASSPOWER public way approach") (id.; Exh. HO-15; Bay State Brief, pp. 25-28, MASSPOWER Brief, p. 7).

For the Bay State ROW approach, Mr. Setian indicated the only practical route follows existing Western Massachusetts Electric Company ("WMECo") electric transmission line rights-of-way (Tr. 3, pp. 27-28).[29] The Company stated that such a route would be approximately 16 miles long (Exh. HO-11; Tr. 3, p. 27). The route would start at a new take station on the Tennessee mainline near the East Longmeadow border with Hampden, travel in a northerly direction within or along the WMECo right-of-way through the Town of Wilbraham, cross the Chicopee River into Ludlow and continue in a northerly direction to the intersection with a second WMECo right-of-way north of Church Street in Ludlow. The route would then follow the second WMECo right-of-way, first in a westerly direction to a point near West Street in Ludlow, and then in a southerly direction, crossing the Chicopee River to the MASSPOWER site in Springfield (Exh. HO-RR-10A; Tr. 3, p. 30). Mr. Setian stated

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28/ Mr. Kekeisen stated that, in addition to the Tennessee ROW approach, MASSPOWER had considered another approach for bringing gas supplies to MASSPOWER prior to settling on the Bay State project -- a MASSPOWER pipeline which would follow a Jet Lines Inc. ("Jet Lines") oil pipeline right-of-way from the Tennessee main line in Hampden to the MASSPOWER site (Exh. BSG-4, p. 6-10; MASSPOWER Brief, pp. 31-32). Mr. Kekeisen stated that this approach was eliminated from consideration after it became apparent that portions of the right-of-way were too narrow to accommodate construction of an additional pipeline (id.). Mr. Kekeisen also stated that MASSPOWER initially had considered buying the Jet Lines facility and converting it from oil to natural gas, but that Jet Lines was not interested in selling the oil pipeline (id.).

29/ Mr. Setian indicated that the use of existing railroad rights-of-way would not be practical for several reasons. Among these is the lack of a direct route to the MASSPOWER facility (Tr. 3, pp. 28-30).

that WMECo had indicated that it would be receptive to Bay State acquiring a new right-of-way alongside its existing rights-of-way, but that it would not favor any pipeline being installed within its existing rights-of-way (Tr. 3, p. 36).

Mr. Setian stated that the Bay State ROW/MTA approach was a modification of the Bay State ROW approach. This approach would follow the same route as the Bay State ROW approach until its intersection with the MTA right-of-way at a point in the vicinity of East Street in Ludlow. The route would then follow the MTA right-of-way west to the intersection with the second WMECo right-of-way, where it heads south to the MASSPOWER facility (Exh. HO-10B; Tr. 3, p. 33). The Company stated that this route would be approximately 13 miles long (id.).

The Company asserted that the Tennessee ROW approach would follow the same route as the Bay State ROW approach (Exh. HO-11; Tr. 3, p. 27). In support of this assertion, the Company provided documentation from Tennessee which specifies use of the WMECo rights-of-way for a possible Tennessee line to MASSPOWER (Exhs. HO-12, HO-13, HO-14). The Company noted that if a Tennessee right-of-way approach were used to serve MASSPOWER, Bay State and its customers would not receive any of the economic or operating efficiencies associated with serving MASSPOWER under the Company's proposed project approach (Exh. HO-18).

In regard to the Bay State MASSPOWER public way approach, the Company stated that there were several possible routes between the Tennessee mainline and the MASSPOWER facility which could be utilized (Exh. HO-15; Tr. 3, pp. 41-43). The Company stated that these routes would travel through the Towns of East Longmeadow and Springfield, would be approximately 12 miles in length, and would travel through heavily developed areas. In addition, Mr. Setian noted that the most practical of these routes would parallel portions of the Company's existing 10-inch distribution system most of the way to the MASSPOWER facility (id.).

Finally, the Company stated that if a Bay State direct pipeline to MASSPOWER were constructed (either under the Bay State ROW approach, the Bay State ROW/MTA approach or the Bay State MASSPOWER public way approach), the Company would be able to interconnect the line with its existing system, thereby gaining some of the benefits associated with the proposed project approach. See Section II.B.2.a, above (Exh. HO-RR-10C; Tr. 3, p.44).[30]

ii. Dedicated Pipeline to Monson and Palmer

The Company stated that the classic approach to serving the Towns of Monson and Palmer ("Bay State's Monson and Palmer public way route") would require construction of (1) approximately 10 miles of eight-inch, 200 psi pipeline along public ways from the Tennessee mainline in Monson to the center of Palmer, and (2) approximately three miles of pipeline from the center of Palmer to the Four Corners area to serve the Palmer Industrial Park (Exhs. BSG-1 p. 15, HO-19; Tr. 3, pp. 48-54). Mr. Setian stated that the route of such an approach would be the same as the Company's primary route under its proposed approach (id.). The Company stated that the classic approach would allow the Company to reach the same potential loads as the proposed approach in the Towns of Monson, Palmer, Ware and Belchertown, but would not provide for possible expansion of service into the Towns of Wilbraham and

30/ The Company stated that both the Bay State ROW and Bay State ROW/MTA approaches would require construction of between 7,000 and 10,000 feet of pipeline to provide the interconnect with the existing system at the Ludlow LNG facility (Exh. HO-RR-10C). In addition, Mr. Setian stated that the routing of the Bay State MASSPOWER public way approach along a portion of the Company's 10-inch distribution system would make an interconnect with the existing system a practical option, the location of such an interconnect would result in reduced benefits relative to an interconnection at the Ludlow LNG facility (Tr. 3, p. 44)).

Ludlow (id.).[31]

3. Ability to Meet the Identified Needs

Before reviewing the proposed and alternative project approaches on the basis of cost and environmental impact, the Siting Council must determine whether the different project approaches are capable of meeting the identified need. 1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 23; 1988 Boston Gas Decision, 17 DOMSC 155 at 169.

The Company asserted that the proposed project approach is capable of meeting the needs of the MASSPOWER facility (Bay State Brief, p. 28). Specifically, the Company stated that by operating the proposed 16-inch pipeline with an inlet pressure of no more than 400 psi at the meter station on the Tennessee mainline, the Company would be able to provide MASSPOWER with 2,000 MMBtu per hour at the required minimum delivery pressure of 340 psi (Exh. HO-20; Tr. 2, pp. 205-211).

The Company also asserted that all of the Bay State versions of the classic approach to serve MASSPOWER -- Bay State ROW approach, Bay State ROW/MTA approach, and Bay State MASSPOWER public way approach -- would utilize 16-inch 500 psi pipelines, and therefore would be capable of meeting the needs of the MASSPOWER facility (Bay State Brief, p. 28). Further, the Company stated that the size and pressure of the Tennessee ROW approach for service to MASSPOWER reflects Tennessee's estimates based on the required delivery pressure and quantity of the MASSPOWER facility, and the expected pressure loss over the length of such a pipeline (Exh. HO-13). The Company also noted that it is Tennessee's policy to install pipelines with

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31/ The Company stated that service to the Towns of Monson and Palmer also could be achieved through a public way extension from the pipeline to MASSPOWER under either the Bay State ROW approach or the Bay State ROW/MTA approach, but noted that such an extension would require approximately twice the construction and associated costs of the single line to Monson and Palmer described above (Exh. HO-RR-10C).

an operating pressure of 877 psi to minimize future pipeline replacements necessitated by system class changes (id.).

The Company asserted that the proposed project approach also is capable of meeting the needs of the expansion areas (Bay State Brief, p. 41). Specifically, the Company stated that by operating the proposed 16-inch pipeline with an inlet pressure of no more than 400 psi at the meter station on the Tennessee mainline, the Company would be able to provide up to 1,000 MMBtu per hour for service to the expansion areas (Exh. HO-20; Tr. 2, pp. 205-211).[32]

In regard to service to the expansion areas under the classic approach, i.e., Bay State's Monson and Palmer public way approach, the Company stated that, while either an eight-inch, 200 psi pipeline or a 12-inch, 99 psi pipeline would have sufficient capacity to provide 1,000 MMBtu per hour to the expansion areas, an 8-inch 200 psi pipeline would be necessary to enable the Company to expand service to Ware and Belchertown in the future (Exh. HO-19; Tr. 3, p. 51).

Finally, MASSPOWER stated that, while the proposed project approach and all versions of the classic approach are capable of meeting the identified project needs, the Tennessee ROW approach for serving MASSPOWER likely could not be completed in as timely a manner as the proposed project approach due to permitting requirements (Exh. BSG-4, p. 9).[33]

32/ The Company stated that it allocated the 1,000 MMBtu per hour among the expansion areas as follows: (1) 100 MMBtu per hour for Wilbraham and Ludlow; (2) 200 MMBtu per hour for Monson; (3) 300 MMBtu per hour for Palmer; and (4) 400 MMBtu per hour for potential future growth in Ware and Belchertown (Tr. 1, p. 163; Exhs. HO-3, HO-RR-2).

33/ Mr. Kekeisen stated that a Tennessee pipeline to serve the MASSPOWER facility would require approval by the Federal Energy Regulatory Commission ("FERC") (Exh. BSG-4, p. 9). Mr. Kekeisen further stated that such approval could take as long as three years (id.).

The record in this proceeding clearly indicates that the proposed project and all versions of the classic approach are technically capable of meeting the identified needs of the MASSPOWER facility and the expansion areas. Further, despite MASSPOWER's assertion regarding the potential for delay in serving MASSPOWER under the Tennessee option, nothing in the record in this case supports the argument that the potential for such a delay would impact the ability of a Tennessee line to fully meet the needs of the MASSPOWER facility. In fact, even if the parties in this case had been able to establish that the proposed project approach could meet the needs of the MASSPOWER facility in a more timely manner than the Tennessee ROW approach, the Siting Council has held that it is inappropriate to attribute an advantage to a petitioner's proposed project approach or project site, relative to an alternative, merely because the petitioner elected to exclusively pursue permitting for its proposal and not for the alternative. 1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 25.

Accordingly, the Siting Council finds that the proposed project and all versions of the classic approach are capable of meeting the two identified project needs.

4. Cost

The Company asserted that its proposed project approach is the least cost way to serve the identified project needs (Bay State Brief, pp. 28, 41). In addition, the Company argued that under the classic two pipeline approach, service to the expansion areas would not be cost-justified (id., p. 41). The estimated costs of the Company's proposed project approach range from a low of $10,557,000 to a high of $16,380,000, depending on routing.[34]

Under the classic two pipeline approach, the Company stated that a dedicated pipeline to serve Monson and Palmer, using Bay State's Monson and Palmer public way approach, would cost $2,500,000.

The Company stated that a dedicated pipeline to serve MASSPOWER, using Bay State's MASSPOWER public way approach, would cost $8,000,000. Thus, the total project cost for the version of the classic two pipeline approach which uses only public ways would be $10,500,000 (Exhs. BSG-1, pp. 15-17, HO-15).[35]

Further, the Company provided estimates of the costs of the dedicated pipeline to MASSPOWER using both the Bay State ROW approach and the Bay State ROW/MTA approach (Exhs. HO-RR-10A, HO-RR-10B). The Company estimates these costs as $16,750,000 and $13,750,000, respectively (id.). Adding the cost of Bay State's Monson and Palmer public way approach, the total project costs for these two versions of the classic approach would be $19,250,000 and $16,250,000, respectively.

Finally, the Company provided a cost estimate for the dedicated pipeline to MASSPOWER using the Tennessee ROW approach (Exhs. HO-12, HO-13). This estimate reflects a cost

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34/ The Company initially estimated the costs of its proposed project approach as $9,100,000 if constructed along the primary route, and $15,200,000 if constructed along the alternative route (Exh. BSG-1, p. 17). The record in this case, however, indicates that the costs of the proposed project are in the range of $10,557,000 to $16,380,000 (see Section III.D, below). For the purposes of comparing the costs of the proposed and alternative project approaches, the Siting Council uses the cost of the primary route as adjusted by the Siting Council in Section III.D, below as the cost of the proposed project.

35/ The Company stated that its estimate of cost for Bay State's Monson and Palmer public way approach did not include the costs associated with extending service from Palmer center towards the Palmer Industrial Park which is in the Four Corners section of Palmer (Tr. 3, pp. 48-49).

to Tennessee of $14,714,000. Thus, the total project cost of this version of the classic approach, including the cost of Bay State's Monson and Palmer public way approach, is $17,214,000 (id.).[36, 37]

Finally, the Company stated that, under any of the versions of the classic two pipeline approach, dedicated service to Monson and Palmer by Bay State's Monson and Palmer public way approach would not be cost-justified (Exh. HO-RR-11).[38] The Siting Council notes that service to Monson and Palmer via Bay State's Monson and Palmer public way approach is not cost-justified for Bay State in the absence of another project revenue stream. The Siting Council also notes, however, that for purposes of our comparison of project approach costs, the Company's willingness to pursue a particular option based on cost, environmental, or reliability concerns, is largely irrelevant. Instead, it is important that we analyze the total costs of each of the approaches that would meet the identified project needs -- project needs identified by the applicant. Here, Bay State has argued and the Siting Council has found that additional energy resources are needed to (1) serve MASSPOWER and (2) serve new load in Monson and

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36/ Mr. Kekeisen stated that the Tennessee alternative would cost MASSPOWER an additional $1,149,750 per year in operating expenses over the Bay State approach (Exh. HO-RR-25). Mr. Kekeisen stated that this additional cost was due to a projected $0.20 per MMBtu Tennessee rate versus a contracted Bay State rate of $0.137 per MMBtu (id.).

37/ The Company stated that the Tennessee right-of-way option would be significantly more costly than the Bay State right-of-way option, even though both options use the same route, due to cost differences resulting from the size and pressure ratings of the pipe (Exh. HO-11).

38/ Specifically, the Company stated that the load potential in Monson and Palmer only would support a capital outlay of $1,600,000 as opposed to the estimated $2,500,000 necessary to construct Bay State's Monson and Palmer public way approach. The Company's analysis is based on load additions forecasted for Monson and Palmer through the year 2019 (Exh. HO-RR-11).

Palmer. An analysis which only addresses the costs or impacts of serving one of the two identified project needs clearly provides an insufficient and inappropriate basis for comparing project approaches.

The record in this proceeding is sufficient to establish that the cost of the Company's proposed project approach ($10,557,000 for the primary route) is significantly less than the total project costs under classic project approaches which include use of either the Bay State ROW approach, Bay State ROW/MTA approach, or the Tennessee ROW approach to serve MASSPOWER ($19,250,000, $16,250,000, and $17,214,000 respectively). The Company's estimate of the total costs of a classic two pipeline project approach which uses the Bay State MASSPOWER public way approach to serve MASSPOWER ($10,500,000), however, are comparable to the costs of the Company's primary route under its proposed approach.

Accordingly, the Siting Council finds that the proposed project (1) is superior to all right-of-way versions of the classic two pipeline approach with respect to cost and (2) is comparable to a classic two pipeline approach using the Bay State public way approach with respect to cost.

5. Environmental Impact

The Company asserted that, with respect to environmental impacts, its proposed project approach was superior to the versions of the classic two pipeline approach which uses any portion of the WMECo right-of-way to serve MASSPOWER -- Bay State ROW approach, Bay State ROW/MTA approach, and Tennessee ROW approach -- in combination with Bay State's Monson and Palmer public way approach (Bay State Brief, pp. 38, 41). The Company also argued that its proposed project approach and the version of the classic approach combining the Bay State MASSPOWER public way approach and Bay State's Monson and Palmer approach were equally benign with respect to environmental impacts (id.).

The Company stated that the environmental impacts of its proposed project would be "generally insignificant" (Tr. 3, pp. 86-87; Bay State Brief, p. 30). In support of this assertion, the Company stated that the impacts almost would be identical to those associated with construction of a small, non-jurisdictional pipeline that the Company would construct periodically as part of routine system expansion activities (Exh. BSG-2, p. 11). The Company identified these impacts as short-term in nature and stated that they consist primarily of localized dust during construction, minimal traffic impacts, and the potential for erosion impacts should it rain while construction activities are ongoing near streams or wetlands (Exhs. BSG-2, p. 11, HO-E-4, HO-E-24). The Company also stated that it did not anticipate any impacts to vegetation, wildlife or historic structures, and that blasting only would be required along limited portions of the alternative route (Exhs. HO-E-17, HO-E-18, HO-E-30, HO-E-34, HO-E-2). The Company indicated that the proposed pipeline would pass within 50 feet of numerous residences along both the primary and alternative routes (Exhs. HO-E-12, HO-E-13).[39]

In regard to the classic two pipeline approach, the Company asserted that the environmental impacts of the 10-mile, eight-inch, 200 psi pipeline which would serve Monson and Palmer under Bay State's Monson and Palmer public way approach also would be insignificant because the entire route would proceed along public ways, and the Company noted that the routing of such a pipeline would be the same as for the Company's proposed project approach (Tr. 3, p. 48; Bay State Brief, p. 41).

In regard to the classic two pipeline approach which includes the Bay State MASSPOWER public way approach for

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39/ For a further description and analysis of the environmental impacts of the Company's proposed project under both the primary and alternative routes, see Section III.E, below.

service to MASSPOWER, the Company stated that the environmental impacts of such a route would again be insignificant and comparable to those of the proposed approach (Exh. HO-15). The Company did not specify potential impacts to residences, wetlands, wildlife, or vegetation along such a route, but noted that the route was already heavily developed along most of its 12-mile length (id.). Specifically, Mr. Setian stated that such a route would travel through areas which are "highly developed, very congested, very costly" and further stated that the Company already had facilities in the streets in these areas (Tr. 1, p. 136). Mr. Setian also indicated that there would be numerous existing underground utilities along the entire length of such a route, consistent with the most congested portion of the primary route in Palmer under the Company's proposed approach, and that hand-digging might be necessary in some areas due to the congestion (Tr. 3, pp. 23-25).[40]

In regard to the other versions of the classic two pipeline approach, Bay State stated that both the Bay State ROW and the Tennessee ROW approaches to serve MASSPOWER would have significantly greater environmental impacts than any public way routing (Exh. HO-12; Bay State Brief, p. 38). Specifically, the Company stated that a route which paralleled the WMECo right-of-ways would: (1) require clearing of a new 25-foot wide right-of-way along the entire distance from the Tennessee mainline to MASSPOWER; (2) pass through approximately 6.3 miles of wetland areas; (3) cross 21 active streams and brooks with flowing water at the crossing points; (4) cross 25 medium- to heavily-traveled roads including two crossings of the Massachusetts Turnpike; and (5) necessitate two railroad crossings (Exh. HO-RR-10A). The Company did not specify the

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40/ The Siting Council notes that the Company proposed a variation to its primary route which would allow it to avoid construction of the 16-inch pipeline through the most congested areas of Palmer. For a further discussion of this variation, see Section III, below.

magnitude of tree clearing which would be necessary under such an approach, but stated that numerous trees would have to be removed, noting specifically sections of the route abutting a state game farm and the Wilbraham Country Club (Exh. HO-13).

The Company stated that by using the Bay State ROW/MTA approach to serve MASSPOWER, the resulting environmental impacts would be reduced relative to the other ROW approaches Exh. HO-RR-10B). The Company stated that such a route would eliminate 0.8 miles of wetland impact and nine active stream and brook crossings (id.). This route would utilize approximately the same portion of the MTA right-of-way as the primary route under the Company's proposed project approach.

The Siting Council notes that the Company's assertions regarding the environmental impacts of public way routing suggest that there are no environmental impacts from public way approaches and that, therefore, only right-of-way routes have to be analyzed for impacts. The Siting Council expressly rejects such a position. The Siting Council previously has reviewed the environmental impacts of numerous public way and right-of-way approaches and routes for siting gas pipelines, and consistently has recognized that many of the potential impacts of such projects may be mitigated adequately through the use of appropriate design and construction techniques. Nevertheless, the Siting Council also has stated specifically that "the relative environmental impacts of an overland pipeline route and an on-street route will vary according to the specific characteristics of the proposed routes" (1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 34). Here, while the Company asserts that construction and operation of high pressure pipelines in public ways is inherently environmentally benign, the proposed project approach clearly raises important land use and safety concerns (see Section III.E).

The Company's proposed project approach would entail construction along public ways for 19 miles for the primary route, and for 29 miles for the alternative route. Serving the identified project needs through one version of the classic two pipeline approach -- a combination of the Bay State MASSPOWER public way approach and the Bay State Monson and Palmer public way approach as described above -- would entail approximately 20 miles of construction along public ways. While construction impacts of pipeline placement in public ways clearly are related to some extent to the length of the route, pipeline size and pressure, congestion in and along the streets of the route, and presence of wetlands or vegetation along the route are much more significant determinants of overall environmental impacts. In comparing the Company's proposed approach to the combined classic public way approaches, the record indicates that the proposed approach travels through considerably less congested areas than the Bay State MASSPOWER public way approach to serving MASSPOWER. Clearly the impacts of construction along 12 miles of highly congested streets through densely populated areas raises significant land use and safety concerns. While the proposed approach raises similar issues along portions of its primary route, the magnitude of such impacts under the proposed approach is considerably less than under the Bay State MASSPOWER public way approach.

The Siting Council notes that the Bay State Monson and Palmer public way approach would have somewhat reduced impacts to the Towns relative to the Company's primary route as proposed because of the use of a smaller, lower pressure single pipeline. Such a small potential reduction in localized impacts, however, clearly are insufficient to offset the increased overall impacts of public way routing through Springfield and East Longmeadow. Therefore, the Siting Council finds that, with respect to environmental impacts, the proposed project is preferable to a classic approach which would combine the Bay State MASSPOWER public way approach with the Bay State Monson and Palmer public way approach.

In regard to the environmental impacts of the classic two pipeline approaches which would combine either the Bay State ROW approach, the Bay State ROW/MTA approach, or the Tennessee ROW approach with the Bay State Monson and Palmer public way approach, it also is clear from the record in this proceeding that the overall long-term environmental impacts of the right-of-way approaches to serving MASSPOWER are significantly greater in regard to wetlands and tree impacts than those of the proposed project approach along either the primary or alternative route. Therefore, the Siting Council finds that the proposed project is superior with respect to environmental impact to all versions of the classic approach which would utilize the WMECo right-of-way to serve MASSPOWER and public ways to serve Monson and Palmer.

Accordingly, the Siting Council finds that the proposed project is superior to all versions of the classic approach with respect to environmental impact.

6. Conclusions: Weighing Need, Cost, and Environmental Impact

The Siting Council has found that (1) the proposed project and all versions of the classic approach are capable of meeting the two identified project needs; (2) the proposed project (a) is superior to all right-of-way versions of the classic approach with respect to cost and (b) is comparable to a classic Bay State public way approach with respect to cost; and (3) the proposed project is superior to all versions of the classic approach with respect to environmental impacts.

Accordingly, the Siting Council finds that, on balance, the proposed project approach is superior to all versions of the classic approach.

It is important to note that the Siting Council has found that the versions of the classic approach which would use either the Bay State ROW approach, the Bay State ROW/MTA approach, or the Tennessee ROW approach to serve MASSPOWER are inferior to the Company's proposed project approach on the basis of both significant costs and environmental impacts. Consequently, because the project costs of the Company's proposed approach and the classic public way approach -- the Bay State MASSPOWER public way approach combined with the Bay State Monson and Palmer public way approach -- are comparable, the Siting Council's finding on project approach is essentially based on a comparison of the environmental impacts of the Company's proposed project approach versus the environmental impacts of the classic public way approach.

Significantly, had we accepted the Company's position that public way routes in fact have insignificant environmental impacts, and therefore, that the impacts of the two approaches are equally benign, the Siting Council would have been unable to make a finding that the Company's proposed project approach was, on balance, superior to all versions of the classic approach. It is precisely because of our attention to such environmental impacts that we are able to endorse the Company's proposed project approach.

III. Analysis of the Proposed and Alternative Facilities

A. Standard of Review

G.L. c. 164, sec. 69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facility siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined that (a) new energy resources are needed, and (b) the applicant has proposed a project that is, on balance, superior to other broad approaches (which we have termed "project approaches") in terms of cost, environmental impacts, reliability and meeting identified need (MASSPOWER Decision, EFSC 89-100, pp. 67-68; 1990 Berkshire Decision, EFSC 89-29 (Phase II), pp. 36-37; Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 38-42 (1989) ("BECo/MWRA"); Turners Falls, 18 DOMSC 160, 175-178; Braintree Electric Light Department, 18 DOMSC 20, 31-40 ("1988 Braintree Decision"); Altresco-Pittsfield, Inc., 17 DOMSC at 387; NEA, 16 DOMSC at 381-409), the Siting Council then has required the petitioner to show that it has examined a reasonable range of practical facility siting alternatives. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Council typically has required the proponent to meet a two-prong test: the proponent must establish that (1) it has developed and applied a reasonable set of criteria for identifying and evaluating alternatives, and (2) it has identified at least two sites or routes with some measure of geographic diversity.[41] BECo/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; 1988 CELCo Decision, 17 DOMSC at 301-303 (1988); NEA, 16 DOMSC at 381-409. Finally, the proponent must demonstrate that the proposed site/route for the facility is superior to the noticed alternative(s) on the basis of balancing cost, environmental impact, and reliability of supply (BECO/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178).

The requirement that a proponent has considered a reasonable range of practical facility alternatives has been extensively discussed in two recent cases, Altresco-Pittsfield and the 1990 Berkshire Decision. In Altresco-Pittsfield, the Siting Council focused on the applicability of the second prong of the practicality test -- the requirement that an applicant identify at least two sites or routes with some measure of geographic diversity. In that case, the Siting Council found that an applicant proposing to construct a cogeneration facility could establish, in certain circumstances, that a second practical facility site does not exist, and, thus, need not provide a "noticed" alternative site (17 DOMSC at 394). However, Altresco-Pittsfield did not change the requirement that an applicant comply with the first prong of the practicality standard -- that an applicant develop and apply a reasonable set of criteria for identifying and evaluating alternatives. Nor did Altresco-Pittsfield alter the requirement that in cases where a noticed alternative is required, the noticed alternative must be geographically distinct from the primary site/route.

41/ When a facility proposal is submitted to the Siting Council, the petitioner is required to present: (1) its preferred facility route or site; and (2) at least one alternative facility route or site. These routes and sites often are described as the "noticed" alternatives because these are the only routes and sites described in the notice of adjudication published at the commencement of the Siting Council's review. In reaching a decision in a facility case, the Siting Council can approve a petitioner's preferred route or site, approve an alternative route or site, or reject all routes and sites. The Siting Council, however, may not approve any site, route, or portion of a route which was not included a notice of adjudication published as part of the proceeding.

In the 1990 Berkshire Decision, the Siting Council focused on the first prong of the practicality standard, commonly referred to as the site selection process. In that case, the Siting Council fully examined the purpose and intent of its review of the siting alternatives, emphasizing the importance of developing and applying a reasonable set of criteria for identifying and evaluating alternatives through the site selection process (EFSC 89-29 (Phase II), p. 41). In that same case, the Siting Council stated that a facility proponent is required to present to the Siting Council a description of its site selection process, including a full explanation of the criteria developed and applied in making siting decisions. Id. The 1990 Berkshire Decision further stated that a review of a comprehensive site selection process, as opposed to a review of the "practicality" of a noticed alternative, is the best way to ensure a reasonable range of practical siting alternatives has been considered. A comprehensive site selection process will ensure that the petitioner has not overlooked or eliminated any alternative route or site -- irrespective of whether it has been included in a published legal notice -- which clearly is superior to the petitioner's preferred route or site.[42]

In order to determine whether Bay State has considered a reasonable range of practical alternatives, the Siting Council first reviews Bay State's site selection process to evaluate whether the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives (see Sections III.C.2 and III.C.3, below). Next, we consider whether that process included consideration of route alternatives with some measure of geographic diversity (see Section III.C.4, below).

42/ In making this distinction, the Siting Council does not mean to invite parties to present an exhaustive list of possible alternative routes and sites which must then be evaluated in our proceeding relative to the preferred route or site. Instead, through a comprehensive review of the petitioner's site selection process, i.e., a consideration of how specific criteria were developed and applied, the Siting Council can determine whether clearly superior routes or sites have been overlooked or eliminated.

Finally, if a petitioner can establish that it has considered a reasonable range of practical siting alternatives, the Siting Council still must review whether the preferred site or route is superior to noticed alternative sites and routes (see Sections III.D, III.E, and III.F, below). This finding is essential because it is at this stage that the Siting Council determines whether sites or routes are are acceptable, i.e., whether they achieve the appropriate balance between cost, environmental impact and reliability. Further, because we expect petitioners to present in their filings alternatives that are, in fact, responsible and reasonable, this more detailed analysis of the noticed alternatives enables the Siting Council to determine which route or site is superior in terms of achieving the appropriate balance between cost, environmental impact and reliability.

B. Description of the Proposed and Alternative Facilities

1. Proposed Facilities

Bay State's proposal consists of: (1) a 16-inch diameter, 500 psi, natural gas pipeline of 18.2 miles in length to be constructed along the primary route, as described below, extending from the Tennessee main line in Monson to the MASSPOWER project in Springfield; (2) a two-inch or four-inch diameter, 99 psi, natural gas pipeline which will be placed in the same trench as the proposed 16-inch diameter pipeline along all sections of the primary route where natural gas service currently is not available; (3) an eight-inch diameter, 99 psi, natural gas pipeline of approximately three miles in length which would extend from the primary route in Palmer and travel north to the Palmer Industrial Park in the Four Corners section of Palmer;[43] and (4) a new meter station to be constructed on

43/ This eight-inch pipeline (which is included in the noticed alternative facilities proposal) was not initially identified by the Company as part of its primary facilities proposal (Exh. BSG-1, Schedule BSG-1-1). However, during the course of the proceeding, the Company indicated that the eight-inch pipeline would be required in response to its commitment to provide service to the Palmer Industrial Park (Tr. 3, p. 109).

a site on Cedar Swamp Road in Monson along the Tennessee main line right-of-way.

From the primary meter station site in Monson, the primary route extends in a generally northerly direction along Cedar Swamp Road and Route 32 North to the Palmer town line, where it crosses the Quabog River. After crossing into Palmer, the primary route continues northwesterly along South Main Street, Main Street, and North Main Street (Route 20) to Route 181. The primary route then continues west along Route 20 to Cottage Avenue in Wilbraham where it crosses the Chicopee River into Ludlow. After entering Ludlow, the primary route continues north along Miller Street to the Massachusetts Turnpike, where it enters Turnpike Authority property. The primary route travels west, along and within the Turnpike Authority property to West Street in Ludlow. From this point, the primary route proceeds south on West Street, crossing the Chicopee River, into the Indian Orchard section of Springfield. The primary route then proceeds south along a short existing Bay State right-of-way to Worcester Street. It then proceeds west on Worcester Street, where it enters onto Monsanto property via either Gate 1 or Gate 2, and continues to the MASSPOWER facility (Exh. BSG-1, Schedule BSG-1-1, p. 1).

The eight-inch, 99 psi line branches off the primary route on Main Street in Palmer. The route turns onto Route 32 where it is also known as Thorndike Street. It continues north along Route 32 to the point where Route 32 and Thorndike Street split, and then follows Thorndike Street northwest to High Street. It follows High Street to Main Street, and travels west on Main Street, terminating at the intersection of Main Street and Route 181, also known as Four Corners (id., pp. 2-3).

2. Alternative Facilities

The Company's alternative facilities proposal consists of: (1) a 16-inch diameter, 500 psi, natural gas pipeline of 18.1 miles in length; (2) an eight-inch diameter, 500 psi, natural gas pipeline of 11.4 miles in length; (3) a two-inch or four-inch diameter, 99 psi, natural gas pipeline which will be placed in the same trench as the proposed 16-inch or eight-inch diameter pipeline along all sections of the alternative route where natural gas service currently is not available; and (4) a new meter station to be constructed on a site on Scantic Road in Hampden along the Tennessee main line right-of-way. From the alternative meter station site in Hampden, the alternative route for the 16-inch diameter pipeline extends in a generally northerly direction along Scantic Road, Cross Road and Monson Road to Glendale Road. It continues north on Glendale Road, crosses the Wilbraham town line, and turns onto Mountain Road. The alternative route then proceeds in a northwesterly direction on Mountain Road to Maple Street and then along Chapel Street to Route 20. The alternative 16-inch diameter pipeline route then travels east on Route 20, and turns north onto Cottage Avenue to the Ludlow town line, where it crosses the Chicopee River. The alternative route then travels northwest on Miller Street to Center Street, southwest along Center Street onto Church Street, and southwest to Rood Street. The alternative route then proceeds in a northwesterly direction along Rood Street to Nash Hill Road, then west on Nash Hill Road to West Street. It turns south on West Street and continues in this direction, crossing the Chicopee River into the Indian Orchard section of Springfield via the West Street Bridge. The alternative route proceeds from this point to the MASSPOWER facility in the same manner as the primary route (id., p. 2).

Bay State's alternative facilities proposal includes an eight-inch pipeline which begins on Glendale Road in Wilbraham, at the intersection with Monson Road. From this point, the eight-inch pipeline travels in an easterly direction along Monson Road to the Monson town line, where Monson Road becomes Wilbraham Road. The eight-inch pipeline then travels east along Wilbraham Road to High Street and southeast on High Street to Margaret Street. It then proceeds north on Margaret Street, Upper Palmer Road and State Avenue, crossing the Quabog River at the Palmer town line where State Avenue becomes Bridge Street. The eight-inch diameter pipeline continues north along Bridge Street to Main Street. The route travels a short distance on

Main Street, and then turns onto Route 32 where it is also known as Thorndike Street. It continues north along Route 32 to the point where Route 32 and Thorndike Street split, and then follows Thorndike Street northwest to High Street. It follows High Street to Main Street, and travels west on Main Street, terminating at the intersection of Main Street and Route 181, also known as Four Corners (id., pp. 2-3).

3. Variations to the Proposed and Alternative Facilities

a. Palmer Variation

Bay State proposes, as a variation to its primary route, the use of town and railroad rights-of-way rather than Main Street in Palmer. The Palmer Variation begins on South Main Street in Palmer, at its intersection with Oak Street. The Palmer Variation travels south along Oak Street, across open land, to a town of Palmer right-of-way. The variation then follows this right-of-way in a northwesterly direction alongside the Vermont Central railroad tracks. The Palmer Variation then crosses under the railroad tracks, leaves the Vermont Central right-of-way, and proceeds northwesterly along Water Street, crossing Bridge Street. After crossing Bridge Street, the variation crosses under Conrail railroad tracks and re-enters the Town of Palmer right-of-way. The variation proceeds northwesterly in this right-of-way to a point on Route 20 (Wilbraham Street) slightly to the west of the intersection of Route 20 and Route 181. At this point, the Palmer Variation rejoins the primary route (id., pp. 1-2; Exh. HO-E-9, Photos 36 to 39).

b. West Avenue Variation

Bay State proposes a second variation to its primary route, which would traverse West Avenue in Ludlow rather than a portion of the Massachusetts Turnpike right-of-way. Using the West Avenue Variation, the proposed pipeline leaves the Massachusetts Turnpike right-of-way at the point where Fuller Street crosses underneath the Massachusetts Turnpike. The West

Avenue Variation travels south on Fuller Street a short distance to the south side of the Massachusetts Turnpike. From this point, the West Avenue Variation travels parallel to the south side of the Massachusetts Turnpike right-of-way to West Avenue, which it follows to the intersection of West Avenue and West Street. From that intersection, the West Avenue Variation rejoins the primary route (Exh. BSG-1, Schedule BSG-1-1, p. 1; Tr. 1, pp. 12-13).

c. Ludlow Variation

Bay State proposes a variation to either the primary or alternative facilities in the Town of Ludlow. The Ludlow Variation follows East Street in Ludlow, beginning at the intersection of East Street and Miller Street as a variation to the alternative facilities, or at the intersection of East Street and the Massachusetts Turnpike as a variation to the primary facilities. From either of these points, the Ludlow Variation proceeds southwest on East Street to Chapin Street, northwest along Chapin Street to Holyoke Street and continues northwest to West Street. The Ludlow Variation rejoins the alternative route at this point. The Ludlow Variation then travels south on West Street, crossing the Chicopee River into the Indian Orchard section of Springfield via the West Street Bridge, where it rejoins the primary route (id., p. 3).

C. Site Selection Process

1. Overview of the Siting Process

Bay State asserts that its site selection process satisfies the requirements of the Siting Council's two-prong test, i.e., that Bay State has developed and applied a reasonable set of criteria for identifying and evaluating alternative sites and that Bay State has proposed a primary and an alternative site with some measure of geographic diversity (Bay State Brief, p. 64). MASSPOWER similarly asserts that Bay State's site selection process satisfies the Siting Council's two-prong test (MASSPOWER Brief, pp. 35-37).

The Company initially determined that a public ways route was the most effective means to meet the following three objectives: (1) to bring gas service to Monson and Palmer; (2) to expand gas service to parts of Wilbraham and Ludlow which currently are not served; and (3) to increase service to MMWEC (Exh. BSG-1, p. 3; Exh. HO-SS-8). During the course of the proceeding Bay State added the objective of serving MASSPOWER and eliminated the objective of providing direct service to MMWEC (id.).

The Company indicated that once the decision was made to place the proposed pipeline in public ways, a corridor was selected which avoids duplicating existing gas service in East Longmeadow, Wilbraham, and Springfield while bringing gas close to areas which currently do not have natural gas service (Exhs. HO-SS-1; HO-SS-8). After Bay State selected the corridor adjacent to its existing service territory, the Company began to choose streets within the Towns of Monson, Palmer, and Wilbraham (id.; Tr. 3, p. 65).

2. Development of Siting Criteria

The Company indicated that its primary site selection criterion was to make gas service available to the greatest number of potential customers, with the direct corollary that the selected route should avoid duplication of existing services (Bay State Brief, pp. 48-49). The other primary criterion upon which Bay State relied was cost, i.e., the Company sought to meet its previously stated objectives in the most cost-effective manner (Tr. 3, pp. 67-69).

In addition to the two primary criteria described above, Bay State identified four other siting criteria: public input, environmental impacts, reliability, and safety (Bay State Brief, pp. 49-50).

Bay State incorporated public input into a number of refinements and modifications which were made to its primary and alternative routes subsequent to its initial filing with the Siting Council (Exh. BSG-1, p. 8; Tr. 3, pp. 70-82). The specific concerns raised by the public include possible damage to recently repaved roads, placement of the pipeline in public ways already congested with a number of existing utilities, and safety considerations associated with the operation of a high-pressure pipeline (Tr. 3, p. 82). The Company stated that public input was given less weight in its site selection process than the primary criterion of making service available to the greatest number of potential customers in the most cost-effective manner (Bay State Brief, p. 49).

Bay State indicated that environmental impacts did not play a significant role in its site selection process (id.). The Company's witness, Mr. Setian, stated that environmental issues do not differ significantly from street to street (Exh. BSG-1, p. 8; Tr. 3, p. 90). Additionally, the Company asserted that the environmental impact of constructing in public ways is minimal (Bay State Brief, p. 49).

Similarly, Bay State indicated that reliability was not a significant consideration in its site selection process because reliable service could be achieved from any route or variation (id.). However, the Company's witness, Mr. Long, acknowledged that the likelihood of third-party damage to a pipeline is greater in certain areas, such as locations where development is occurring, than in other areas, such as a turnpike right-of-way, where excavation is unlikely (Tr. 2, pp. 12-15). Mr. Long also stated that such considerations, in his opinion, are relevant to the siting of a pipeline (id., p. 15).

Finally, although Bay State identified safety as a site selection criterion, the Company asserted that safety is properly addressed through design considerations rather than siting considerations (Exh. HO-Bouc-6; Tr. 2, p. 10; Tr. 3, p. 69). Accordingly, safety considerations were not included in the Company's site selection process (Tr. 3, p. 69). Bay State further asserted that the Siting Council has no jurisdiction over the safety aspects of the proposed gas pipeline (Bay State Brief, p. 42).

Bay State's proposed pipeline is the first natural gas pipeline reviewed by the Siting Council which encompasses both transmission functions (high-pressure natural gas service to an industrial end-user) and distribution functions (low-pressure natural gas service to numerous end-users).[44] The primary site selection criterion identified by Bay State, to make gas service available to the greatest number of potential customers, is consistent with the distribution function of the proposed pipeline. However, the Siting Council previously has recognized the appropriateness of siting high-pressure transmission pipelines in a manner which avoids densely populated areas (1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 88). The Siting Council notes that the dual purposes of the proposed pipeline offer competing, and in some instances conflicting, siting considerations. And, while the Company's primary site selection criterion is appropriate for the distribution function of the proposed pipeline, it fails to adequately consider the transmission function.

The Siting Council previously has found that criteria such as cost, environmental impacts, and reliability generally are appropriate for siting natural gas pipelines. 1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 51. However, Bay State gave essentially no weight to environmental impacts and reliability in its site selection process due to the Company's contention that these factors do not vary significantly from one route along a public way to another.[45]

The environmental impact of distinct public ways routes will vary depending on factors such as the need for blasting, clearing of trees or other vegetation, and compatibility with existing land use. Such potential impacts clearly should be included in a company's identification and evaluation of potential routes for natural gas pipelines.

44/ For the purposes of this section, the Siting Council uses the terms "transmission" and "distribution" solely as defined above. The Siting Council reviewed a proposed distribution pipeline in Boston Gas Company, 17 DOMSC 155 (1988) ("1988 Boston Gas Decision"). In the 1990 Berkshire Decision, the Siting Council reviewed a high-pressure pipeline which was designed to serve one large industrial end-user.

45/ The Siting Council compares the environmental impacts and reliability of the proposed routes and variations in Sections III.E and III.F, respectively, below.

With regard to reliability, the Siting Council previously has stated that possible supply interruptions due to third party excavation and rupture of the pipeline vary among distinct public ways routes according to factors such as significant traffic and development activity. Id. at 96-98. The Company's witness, Mr. Long, similarly noted that such reliability considerations are relevant to pipeline siting (Tr. 2, p. 15). His statements are consistent with the Siting Council's established position that a comprehensive site selection process for a natural gas pipeline must include reliability criteria. (1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 51).

With regard to safety, the Siting Council expressly has rejected the argument that safety is addressed appropriately through design considerations alone. Id. at 88. In the 1990 Berkshire Decision, the Siting Council stated that installation and operation of a new pipeline always poses some risk of accident. Further, it is reasonable to assume that the degree of risk bears some relationship to the length of pipeline and the extent of human exposure along the route. Therefore, the Siting Council must evaluate the safety of proposed high pressure pipelines not only in the context of design and engineering features, but also in the context of siting considerations.[46] Siting Council precedent clearly recognizes the appropriateness of siting high-pressure natural gas pipelines in a manner which minimizes human exposure to possible pipeline accidents. Id. at 88-89.

Finally, with regard to public input, the Siting Council stated in the 1990 Berkshire Decision that it "strongly encourages developers to incorporate community input into their site selection process." Id. at 52. In response to public input, and after its initial filing, Bay State identified alternative routes and variations which in some measure address

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46/ The Siting Council addresses Bay State's related argument that the Siting Council has no jurisdiction over the safety aspects of the proposed pipeline in Section III.E.2, below.

deficiencies in the site selection criteria initially identified. Specifically, in its revised filing, Bay State proposed alternatives and variations which address concerns regarding compatibility with existing land use (i.e., avoiding recently repaved roads and public ways already congested with existing utilities) as well as safety and related reliability concerns. Public input prompted the Company to incorporate relevant information into its site selection process.

In sum, the Company's original siting criteria, while generally appropriate, overlooked several important considerations. The Company's criteria failed to recognize the competing siting concerns raised by transmission and distribution functions, the differences among distinct public ways routes with regard to environmental and reliability considerations, and the relevance of safety as a siting consideration. Eventually, however, as a result of public input and other considerations the Company was led to make a number of amendments to the original proposal. These amendments reflect additional criteria that allow the Siting Council to find that Bay State developed a minimally acceptable set of criteria for siting the proposed pipeline.

The Siting Council emphasizes, however, that the manner in which the siting criteria were developed was far from optimal and greatly delayed the progress of this proceeding. Although Bay State eventually proposed routes in response to public input which address certain relevant concerns, a comprehensive site selection process initially should incorporate appropriate criteria rather than relying on public input to act as a "check" on company oversights (especially given that public input frequently will not address all relevant concerns). This case has proceeded through numerous route and design changes and has required five Siting Council public hearings in the Springfield area. A filing before the Siting Council should not be the occasion to begin to identify and refine relevant siting criteria; a Siting Council filing should reflect a comprehensive process.

3. Application of Siting Criteria

a. Description

As stated in Section III.A, above, the Siting Council examines whether an applicant has developed a reasonable set of criteria for identifying and evaluating possible sites, as well as whether those criteria were applied consistently and appropriately in a manner which ensures that no clearly superior alternatives have been overlooked or eliminated.

Bay State made a number of modifications and refinements to its proposed primary and alternative routes subsequent to its initial filing with the Siting Council, as discussed in Section III.C.2, above. These modifications and refinements allowed the Siting Council to find that the Company developed a minimally acceptable set of criteria. In order to examine whether the Company applied its site selection criteria consistently and appropriately in a manner which ensures that no clearly superior alternatives have been overlooked or eliminated, the Siting Council will review the Company's application of its siting criteria to its initial primary and alternative routes, as well as to each of the subsequent modifications.

i. The Company's Initial Route Options

Bay State's witness, Mr. Setian, stated that the Company selected its initial primary route because it brought the proposed pipeline to the population centers in the Towns of Monson and Palmer, and to those parts of Wilbraham which currently do not have gas service (Exh. HO-SS-1; Tr. 3, pp. 65-66). Mr. Setian noted the limited number of public ways options through the Monson-Palmer-Wilbraham corridor which would achieve the Company's objective of maximizing access to new customers while avoiding duplicating existing gas service (id.). Mr. Setian also stated that the originally proposed primary route was the most cost-effective means of meeting the Company's stated objectives (Exh. BSG-1, p. 3; Tr. 3, pp. 66-67). The Company noted that environmental impacts and safety did not play a role in its selection of the original primary route because, in the Company's opinion, these factors did not vary from one public ways route to another, but rather they were addressed by overall project design (Bay State Brief, pp. 52, 54). With respect to reliability, the Company stated that system reliability is enhanced by the primary route's interconnection with Bay State's existing system and proximity to Bay State's LNG facility (id.). Finally, Bay State stated that it used public input to reinforce its assessment of potential market exposure (id., p. 54).

The Company stated that it selected its original alternative route as a cost-effective means of bringing gas service to the previously identified population centers with a geographically diverse route (Tr. 3, pp. 67-69). As with the original primary route, the Company asserted that environmental and safety considerations do not vary significantly among public ways routes, and that reliability would be enhanced by the planned interconnection with Bay State's existing system (Bay State Brief, pp. 59-60). The Company also stated that it used public input to help determine market exposure along the alternative route (id., p. 59).

ii. Modifications to the Company's Initial Route Options

One of the initial modifications to the primary route proposed by Bay State was the Palmer Variation (Exh. BSG-1, pp. 3-4). Mr. Setian stated that the Company proposed this variation in response to public input (Tr. 3, pp. 72-74). Specifically, citizens had expressed concerns about routing a high-pressure natural gas pipeline along Main Street in Palmer, and the Palmer Water district raised concerns regarding a possible lack of space due to existing utilities under Main Street (id., p. 72). Mr. Setian stated that the Company proposed the Palmer variation to provide a back-up in case mapping indicated that insufficient space exists under Main Street for the proposed pipeline, and in response to public concerns (id., pp. 72-74). However, Mr. Setian explained that the Company considers the primary route to be preferable to the Palmer Variation because the primary route is more cost-effective (id., p. 74).

Another initial modification to the primary route proposed by Bay State was the change from Red Bridge Road and East Street in Wilbraham and Ludlow to Route 20 (Exh. BSG-1, p. 4). Mr. Setian stated that this change similarly was prompted by public concern (Tr. 3, p. 75). In particular, concerns were raised regarding the bridge which would be used and possible disruption to recent repaving along East Street (id., p. 76). The Company proposed the Route 20 modification (and eventually eliminated the Red Bridge Road and East Street segment) because it would alleviate public concern without affecting the Company's ability to meet its objectives in a cost-effective manner (id., pp. 76-77). Mr. Setian emphasized that Bay State was confident that pipeline construction would not damage the newly paved surface on East Street, and that the Company proposed this modification solely to allay public concern (id., pp. 77-78).

The next modification proposed by Bay State was the route segment within the Massachusetts Turnpike right-of-way in Ludlow (Exh. BSG-1, p. 4). Again, this modification was proposed in response to community concerns (Tr. 3, p. 79). The Company stated that it proposed routing the pipeline along the Turnpike right-of-way because it did not negatively affect the Company's ability to reach new customers or the cost-effectiveness of the proposed project (Bay State Brief, pp. 55-56). Additionally, the Company indicated that the strong support for this route segment expressed by the Ludlow Board of Selectmen, as well as the area's State Representative and State Senator, increased the Company's confidence that it could obtain the permits necessary for construction in the Turnpike right-of-way (id., p. 56).

The final modifications proposed by Bay State were placement of the proposed pipeline along West Avenue in Ludlow, where that street parallels the turnpike, and clarification that the proposed pipeline could be placed anywhere within the turnpike right-of-way, rather than only along the south side of the right-of-way, as originally proposed (Exh. BSG-1, pp. 4-6). Mr. Setian explained that the West Avenue variation was proposed as a result of an oversight in the Company's original filing of the Massachusetts Turnpike right-of-way segment (Tr. 3, p. 80).

In addition to the modifications described above, the Company evaluated and rejected a modification to the primary route in the Town of Monson (Exh. BSG-1, pp. 10-12). This modification would have followed an abandoned electric company right-of-way, thus avoiding Main Street in Monson (id., p. 10). The electric company right-of-way initially was suggested by the Highway Surveyor for the Town of Monson (id.). The Company stated that it made an on-sight inspection of the electric right-of-way which revealed that significant environmental impacts would result from pipeline construction due to the presence of wetlands, including streams and marshlands, and ledge outcroppings, which require substantial blasting (id., pp. 10-11; Tr. 3, pp. 86-87). The Company noted that the cost of the project would increase as a result of construction in an environmentally sensitive area, and that use of the electric right-of-way would reduce the pipeline's ability to reach new customers (Exh. BSG-1, p. 11). Accordingly, the Company did not propose the electric right-of-way as an alternative to the primary route along Main Street in Monson (id.).

b. Analysis

In identifying and evaluating its original primary and alternative routes, Bay State applied its stated initial criteria in a consistent manner. Both routes seek to maximize the number of potential new customers in a cost-effective manner. Additionally, in selecting both routes, the Company relied upon public input solely to confirm market estimates. Finally, Bay State did not consider environmental impacts or safety considerations in its selection of either route as a result of its position that these factors do not vary among public ways routes. Bay State did consider reliability in terms of the ability of both routes to interconnect with Bay State's existing system and proximity to its LNG facility.

The Company also has demonstrated that it applied its site selection criteria in a consistent manner in its identification and evaluation of modifications to its original primary and alternative routes. The modifications which eventually were proposed by the Company do not inhibit the proposed pipelines' ability to reach potential new customers in a cost-effective manner, while they do respond to community concerns. The modification which was evaluated by the Company and subsequently rejected would have reduced the number of potential new customers, increased costs, and resulted in greater environmental impacts.

In sum, Bay State has demonstrated that it consistently applied its initial criteria to the originally proposed primary and alternative routes, as well as to the subsequent modifications evaluated by the Company. The Siting Council has stated its concern that Bay State's initial site selection criteria failed to recognize the competing siting concerns raised by the transmission and distribution functions of the proposed project, the differences among public ways routes with regard to environmental and reliability considerations, and the relevance of safety as a siting consideration (see Section III.C.2, above). The modifications proposed by the Company in response to public input help address these concerns. The Palmer Variation offers the opportunity to separate the transmission and distribution functions of the proposed project by placing the larger, high-pressure transmission pipeline along a separate right-of-way while routing the smaller, low-pressure distribution pipeline along Main Street in Palmer. The remaining modifications provide routing options which address environmental considerations such as compatibility with existing land use, and reliability considerations. Finally, the Company's analysis of the Monson electric right-of-way demonstrates that this modification is not clearly superior to the proposed primary route.

Accordingly, the Siting Council finds that Bay State has applied its site selection criteria consistently and appropriately in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to its proposal.

The Siting Council notes that it is able to make this finding due to the modifications proposed by the Company in response to community input. Because Bay State initially developed an incomplete set of siting criteria, the Company had to rely on active citizen participation subsequent to its original filing to identify potentially superior siting options. Although the Siting Council encourages companies to incorporate community input into their siting decisions, the ultimate responsibility for demonstrating that clearly superior options have not been overlooked or eliminated continues to rest squarely with the applicant. Project proponents are well-advised to develop and apply a site selection process which ensures that clearly superior siting options are not overlooked or eliminated.

4. Geographic Diversity

In this section the Siting Council considers the second prong of our practicality test -- whether the Company's site selection process included consideration of route alternatives with some measure of geographic diversity.

Bay State argues that the second prong of the Siting Council's test is met by the nearly complete geographic diversity of the primary and alternative routes (Bay State Brief, p. 64). MASSPOWER similarly states that the alternative route represents a geographically distinct route from the primary route (MASSPOWER Brief, p. 37).

The record indicates that the primary and alternative routes are entirely geographically diverse, with the exception of the short distance from the West Street Bridge in Springfield to the MASSPOWER facility and along Miller Street in Ludlow (Exh. BSG-1, Schedule BSG-1-1, pp. 1-2). Accordingly, the Siting Council finds that Bay State's site selection process included consideration of at least two pipeline routes and meter station sites with some measure of geographic diversity.

5. Conclusions on Site Selection Process

In order to demonstrate that it has considered a reasonable range of practical siting alternatives, the Siting Council requires a petitioner to demonstrate that: (1) it has developed and applied a reasonable set of criteria in making siting decisions; and (2) it has considered alternatives with some measure of geographic diversity.

The Siting Council has found that Bay State developed a minimally acceptable set of criteria for siting the proposed pipeline. The Siting Council also has found that Bay State applied its siting criteria consistently and appropriately in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to its proposal. Additionally, the Siting Council has found that Bay State's site selection process included consideration of at least two pipeline routes and meter station sites with some measure of geographic diversity.

Accordingly, the Siting Council finds that Bay State considered a reasonable range of practical siting alternatives.

D. Cost Analysis of the Proposed and Alternative Facilities

Bay State provided cost estimates for its primary and alternative routes, as well as for the Palmer Variation and the Ludlow Variation (Exh. BSG-1, p. 17, Schedules BSG-1-2 and BSG-1-3).[47] The Company's initial estimates were $9,100,000

47/ The Company indicated that the West Avenue Variation would reduce the cost of the primary route by avoiding the MTA lease and landscaping costs along the segment of the primary route that would be replaced (Tr. 3, pp. 126-127). On September 20, 1990, the Company provided an update to Exhibit HO-SS-12 which sets forth estimates of the cost of landscaping charges and annual lease arrangements with the MTA. The Hearing Officer hereby accepts into the record this information, which has been marked as part of Exhibit HO-SS-12. The additional information provided by the Company demonstrates that the West Avenue Variation would reduce the annual lease cost of the primary route by approximately $12,250 per year for the first five years, and possibly by a somewhat larger amount (footnote continued) for the primary route and $15,200,000 for the alternative route (id.). The Company argued that use of the Palmer Variation would add $550,000 to the cost of the primary route (Exh. BSG-1, p. 9, Schedule BSG-1-2). Finally, the Company estimated that the Ludlow Variation would increase the cost of the primary route by $220,000, while it would decrease the cost of the alternative route by $1,020,000 (Exh. BSG-1, Schedules BSG-1-2 and BSG-1-3). During the course of the proceeding a number of factors were identified which require modification of these initial estimates.

With regard to the primary route, the Company's initial estimate of $9,100,000 included $8,700,000 for the 16-inch pipeline and $400,000 for the two-inch and four-inch distribution pipeline (Exh. BSG-1, p. 17). Additionally, the Company indicated that preliminary engineering, regulatory and permitting expenses would add $750,000 to the total project cost (id.). Subsequent to its initial cost estimate, Bay State noted that compliance with requests from the Towns of Monson and Palmer regarding pipeline placement would increase the cost of the primary route by approximately $260,000 (Exh. HO-RR-32). The Company indicated that the cost of the eight-inch pipeline to serve the Palmer Industrial Park, which was not included in its initial estimate, would be approximately $465,000 (Exh. HO-RR-18). Finally, the Company noted that its initial cost estimate for the primary route improperly included $18,000 for an option to purchase land for the alternative meter station site (Tr. 3, p. 102). With the above-described adjustments, the record indicates that the total project cost of the primary

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(footnote continued) in subsequent years (Exh. HO-SS-12; Tr. 3, p. 126). The Company also indicated that it has committed to landscaping fees of up to $100,000 for the entire MTA right-of-way segment of the primary route, which would be reduced somewhat by the West Avenue Variation (id.). Even with the additional information provided by the Company, the cost differential between the primary route and the primary route with the West Avenue Variation appears to be insignificant. Therefore, further discussion comparing the costs of the primary route and the primary route with the West Avenue Variation is not warranted.

facilities proposal is $10,557,000.[48]

Bay State's initial $15,200,000 estimate for the alternative route included $13,200,000 for the 16-inch pipeline and $2,000,000 for the two-inch and four-inch distribution pipeline (Exh. BSG-1, p. 17). As with the primary route, the Company indicated that $750,000 should be added to the cost for the alternative route to account for preliminary engineering, regulatory, and permitting expenses (id.). Subsequent to its initial cost estimate, Bay State noted that compliance with requests from the Towns of Monson and Palmer regarding pipeline placement would increase the cost of the alternative route by approximately $430,000 (Exh. HO-RR-32). Including these modifications, the record indicates that the total project cost for the alternative route is $16,380,000.[49]

The Company stated that the Palmer Variation would increase the cost of the primary route by $550,000: $300,000 for construction of the two-inch or four-inch diameter distribution pipeline on Main Street, and $250,000 for permit and construction contingencies associated with the two railroad crossings for the 16-inch diameter pipeline (Exh. BSG-1, p. 9, Schedule BSG-1-2). However, in addition to the contingency costs associated with the two railroad crossings for the 16-inch diameter pipeline, the record indicates that the estimated cost of placing the 16-inch diameter pipeline along the separate right-of-way is $1,023,000, which is $28,000 more that the estimated cost of $995,000 for the 16-inch diameter pipeline

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48/ The Company's cost estimate includes a ten percent contingency for materials, and 50 percent to 100 percent contingencies for construction expenses (Exh. HO-RR-15). Total contingency costs for the primary route are $1,880,650, or approximately 18 percent of the total project cost (id.; Exh. HO-RR-18).

49/ The Company's cost estimate for the alternative route, as with the primary route, included a ten percent contingency for materials and 50 percent to 100 percent contingencies for construction expenses (Exhs. HO-RR-15, HO-RR-20). Total contingency costs for the alternative route are $4,677,775, or approximately 28 percent of the total project cost (id.).

segment of the primary route on Main Street in Palmer (Exh. BSG-1, Schedule BSG-1-2). Thus, the record indicates that the Palmer Variation -- including both the 16-inch diameter segment along the separate right-of-way and the two-inch or four-inch diameter segment along Main Street -- would cost approximately $578,000 more than the primary route, bringing the total cost to $11,135,000. This is approximately five percent more than the cost of the primary route.

In sum, the record in this case indicates that the estimated costs of the primary and alternative routes and variations are as follows:

Primary Route	$10,557,000
Primary Route with Ludlow Variation	10,777,000
Primary Route with Palmer Variation	11,135,000
Alternative Route with Ludlow Variation	15,360,000
Alternative Route	16,380,000

Based on the foregoing, the Siting Council finds that the Company's primary route is preferable to the alternative route with respect to cost.

Further, due to the small percentage difference in cost between the primary route and the primary route with the Ludlow or Palmer Variation (two percent and four percent, respectively) and the significant allowance for contingencies included in the Company's primary route cost estimate (18 percent), the Siting Council finds that the primary route with the Ludlow Variation and the primary route with the Palmer Variation are comparable to the primary route with respect to cost.

E. Environmental Analysis of Proposed and Alternative Facilities

1. Environmental Impact of the Primary Route and Variations

a. Water and Land Resources

As noted above, the Company asserted that environmental impacts do not vary from street to street, and that the primary route will have minimal environmental impacts (Bay State Brief, p. 52). Similarly, MASSPOWER contends that any short-term environmental impacts will be minimized through the use of environmentally sensitive construction practices, and that there will be no long-term adverse environmental impacts associated with the proposed pipeline (MASSPOWER Brief, pp. 39-42).

Bay State noted that erosion and sedimentation into nearby wetland areas or surface waters could result from rain during construction of the proposed pipeline along the primary route, the Ludlow Variation, the West Avenue Variation, and the Palmer Variation (Exhs. HO-E-21, HO-E-24). The Company provided National Wetlands Inventory Maps for the proposed pipeline routes which indicate the presence of numerous wetland and surface water areas in the vicinity of the proposed primary route and variations (Exh. HO-E-22). The Company maintains that it will be able to minimize potential erosion impacts through the use of erosion control measures such as hay bales, silt stop fencing and sand bags (Exhs. HO-E-21, HO-E-24).

In addition to potential erosion along streets during construction of the proposed pipeline, Bay State noted the possibility of erosion and sedimentation into streams and rivers at bridge crossings (Tr. 5, p. 28). Specifically, the Company indicated that erosion control measures would be necessary at crossings of small streams with no concrete pier or support at the point where the pipeline exits the streambank and joins the bridge (id., pp. 28-29). Bay State also noted that waterways licenses from the Department of Environmental Protection will be required for the proposed Chicopee and Quabog River crossings (Exh. HO-E-49).

The Company demonstrated that the primary route, the Ludlow Variation, and the West Avenue Variation follow public streets and bridges, and therefore do not directly traverse any wetlands (Exh. BSG-1, Schedule BSG-1-1). Bay State noted, however, that there was a possibility that wetlands existed along the Palmer Variation, due to the presence of vegetation along the sewer right-of-way which is common to wetland areas (Exhs. HO-E-48, HO-E-49; Tr. 3, p. 89). The National Wetlands Inventory Maps provided by the Company indicate the presence of wetlands containing scrub and/or shrub wetland vegetation in two areas along the sewer right-of-way portion of the Palmer pipeline, Bay State would attempt to circumvent the root system, and if this were not possible, the Company would consult a certified arborist (id.; Tr. 5, pp. 56-58). Bay State also noted that spoil removed from the trench generally would be banked along the side of the trench requiring most protection from traffic (Exh. HO-E-19). The Company acknowledged that some clearing of vegetation would be required along the sewer right-of-way portion of the Palmer Variation (Tr. 3, p. 89).

The record indicates that construction of the proposed facilities along the primary route, the Ludlow Variation, and the West Avenue Variation will not require placement of the pipeline or pipeline construction within wetland areas. Although Bay State has noted the presence of vegetation typical of wetland areas along a portion of the Palmer Variation, the record includes mapped identification of wetlands in only two such areas, both of which appear to be more than 100 feet from the Palmer Variation. Where wetlands and surface waters do exist in the vicinity of the primary route, the Palmer Variation, the Ludlow Variation, or the West Avenue Variation, appropriate state and local agencies can require mitigation measures under the Wetlands Protection Act to help ensure minimal impact to these areas. In addition to erosion control measures, potential alteration of subsurface drainage can be prevented through the use of measures such as anti-seepage collars. The Company also has the flexibility to adjust alignment of the pipeline within the public way or sewer easement in order to minimize any adverse impact on sensitive areas along any of the routes. The Siting Council expects the Company to comply with the requirements of the appropriate conservation commissions in order to ensure minimal impacts on wetland resource areas.

The record also indicates that construction of the proposed facilities along the primary route, the Palmer Variation, the Ludlow Variation, or the West Avenue Variation will not require removal or trimming of trees, and that the Company will be able to avoid damage to roadside trees through circumvention of roots and consultation with a certified arborist. Additionally, Bay State's practice of banking spoils along the side of the trench requiring most protection from traffic will locate spoils toward the center of the road, and thus away from any tree roots bordering the side of the road. The record further indicates that construction along the primary route, the Palmer Variation, the Ludlow Variation, or the West Avenue Variation will require minimal clearing of vegetation.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, the Palmer Variation, the Ludlow Variation, or the West Avenue Variation, with the utilization of mitigation measures, will have an acceptable impact on water and land resources.

b. Land Use, Traffic and Safety

i. Land Use and Traffic

The Company stated that the proposed primary route, Palmer Variation, Ludlow Variation, and West Avenue Variation pass through residential, commercial, and industrial zoned areas, and that residential and commercial development are predominant along these routes (Exh. HO-E-1).

With respect to the primary route, Bay State acknowledged that as a result of its intention to reach as many new customers as possible, the primary route traverses the most densely developed areas of the Towns of Monson and Palmer (Exh. HO-SS-1; Tr. 3, pp. 65-66). The record indicates that the primary route passes within 15 feet of one residence in Monson, and within 50 feet of numerous residences along the entire route, with the greatest concentration of residential development along Main Street in Monson and Palmer (Exhs. HO-E-2, HO-E-13). The Company indicated that its primary route passes within one-quarter mile of two day care centers, four schools, one hospital, and a home for the aged, and within one-half mile of an additional two schools and a hospital (Exh. HO-E-3). The record shows that the ancillary eight-inch pipeline proposed to serve the Palmer Industrial Park passes within one-quarter mile of an additional school (id.). The Company demonstrated that the primary meter station site is not within 50 feet of any residences, and is not located within one-half mile of any sensitive receptors (Exhs. HO-E-13; HO-E-9, Photo 26; HO-E-3).

The Company demonstrated that the Ludlow Variation passes within 50 feet of more than 50 residences (whereas the primary route passes within 50 feet of 17 residences along the segment which would be replaced by the Ludlow Variation) (Exh. HO-E-13). The record also shows that the Ludlow Variation brings the pipeline within one-quarter mile of three more schools than the primary route (Exh. HO-E-3).

The record indicates that the West Avenue Variation, like the primary route along this segment, does not pass within 50 feet of any residences, and does not travel near any day care centers, schools, hospitals, or other sensitive receptors (id.; Exh. HO-E-13).

Finally, the record indicates that the Palmer Variation passes within 15 feet of three residences, and within 50 feet of an additional 16 residences (Exhs. HO-E-12, HO-E-13). The Company demonstrated that the Palmer Variation bypasses the most densely populated area of Palmer, thus avoiding 14,000 feet of virtually continuous residential and commercial development (Exhs. HO-E-9, Photos 36-39; BSG-1, Schedule BSG-1-2). The Company indicated that, in comparison with the proposed primary route through Palmer, the Palmer Variation increases slightly the distance between the 16-inch pipeline and two elementary schools (Exh. HO-E-3).

Bay State provided a copy of the Massachusetts Historical Commission's ("MHC") determination that the proposed pipeline, along the primary route or variations, will not affect significant cultural, historical, or archaeological resources (Exh. HO-E-2). The Company further demonstrated that the only structure along any of the proposed routes or variations which currently is listed on the National Register of Historic Places is the Monson Town Hall on Main Street in Monson (id.). However, the Company provided a list of numerous structures along the proposed routes which currently are on the MHC's inventory of potentially significant structures, but which have not yet been evaluated (id.).

With respect to traffic impacts, the Company indicated that at least one lane of traffic will be open at all times during construction along all routes and variations, and that access and egress along the proposed roadways will be maintained at all times except for relatively short periods of time when construction takes place directly across a driveway (Exhs. HO-E-5, HO-E-6). Bay State indicated that it will backfill the pipeline trench at the end of each day, and that the Company will apply the base coat of pavement within two to three days of completing construction, and the final coat of pavement two to six months later, after settling has occurred (Exh. HO-E-29). The Company also stated that construction along the Massachusetts Turnpike will take place either in the center strip, or in the unpaved land adjacent to the Turnpike, so that traffic disruption along the Turnpike will be minimized (Exh. HO-E-43).

ii. Safety

(A) Jurisdiction

Bay State asserts that the Siting Council does not have jurisdiction over the safety aspects of the proposed pipeline (Bay State Brief, p. 42). The Company acknowledges that, pursuant to G.L. c. 164, secs. 69H and 69I, the Siting Council is required to implement policies to ensure a necessary energy supply for the Commonwealth at the lowest possible cost and with a minimum impact on the environment, and that Bay State must obtain the Siting Council's approval before it can commence construction of the proposed pipeline (id.). However, the Company argues that these statutes do not allow the Siting Council to make determinations regarding safety issues when evaluating proposed facilities (id.). Therefore, the Company states that the Siting Council may not establish safety criteria and potentially withhold approval of the proposed pipeline based on such criteria (id.).

Bay State further notes that, pursuant to G.L. c. 164, sec. 75, the MDPU is the agency clearly empowered by statute to supervise the safety of gas utility operations (id.). The

Company states that it has received MDPU approval to operate the proposed pipeline at pressures up to 500 psi for all segments of the proposed pipeline except the Springfield extension to serve MASSPOWER, and that the Company's petition to operate the Springfield segment at pressures up to 500 psi currently is pending before the MDPU (id., pp. 42-43). Accordingly, Bay State urges the Siting Council to acknowledge the determinations of its sister agency and avoid repeating a review of safety issues already completed by the MDPU (id., p. 43). Bay State cites the Siting Council's 1984 Boston Gas Decision, 11 DOMSC 159 at 164, in which the Siting Council adopted the determination of the Coastal Zone Management Unit of the Executive Office of Environmental Affairs, as a precedent for Siting Council reliance upon the findings of another agency (id.).

Section 69I of Chapter 164 of the General Laws states that companies planning expansion of existing facilities shall provide a minimum of data for review concerning, among other impacts, land use impact. Further, G.L. c. 164, sec. 69J states that the Siting Council shall approve a long-range forecast provided that, among other conditions, "plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." In accordance with these statutes, the Siting Council's regulations at 980 CMR 7.07(7)(d)(2) require companies which propose natural gas pipelines to provide a description of:

> land use, both existing and proposed, including types and densities in developed areas, agricultural and other open uses, parks and recreation areas, areas designated for protection as natural preserves or historic or scenic districts, road crossings and traffic patterns, nearby utility or transportation corridors, cemeteries and schools....

Additionally, 980 CMR 7.07(7)(d)(3) requires petitioners to provide an evaluation of the impact of the proposed facilities on, among other features, land use.

Clearly, the Siting Council's statutes and regulations envision our review of the compatibility of proposed natural gas pipelines with existing and planned land use and development. As the Siting Council stated in Section III.C.2, above, installation and operation of a new pipeline always poses some risk of accident. Further, it is reasonable to assume that the degree of risk bears some relationship to the length of pipeline and the extent of human exposure along the route. Thus, the Siting Council evaluates proposed and alternative routes for high pressure pipelines based on, among other factors, the degree to which such pipeline routes minimize human exposure to possible accidents and are otherwise compatible with established land use.

We fully agree with Bay State that the Siting Council, where applicable, should acknowledge the determinations of other agencies with jurisdiction over the proposed project, such as the MDPU. Indeed, G.L. c. 164, sec. 69H, states that:

> In carrying out its functions, the council shall cooperate with, and may obtain information and recommendations from every agency of the state government and of local government which may be concerned with any matter under the purview of the council.

In fact, there have been numerous instances in which the Siting Council has relied on the determinations of the MDPU (see e.g., 1989 NEPCo Decision, 18 DOMSC 383, 396-397 (1989), Altresco-Pittsfield, Inc., 17 DOMSC at 366-367 (the Siting Council accepts an MDPU-approved power sales agreement as prima facie evidence of a utility's need for additional energy resources); Massachusetts Electric Company, 18 DOMSC at 351-352, 359-360, 362, Boston Edison Company, 18 DOMSC 73, 114-115, 121, 125 (the Siting Council accepts in supply plan reviews the MDPU's oversight of a utility's resource solicitation for QF power as evidence that the utility has identified a reasonable range of QF options)).. More recently, in another natural gas pipeline facility case, the Siting Council acknowledged the MDPU's approval of Berkshire Gas Company's request to operate a pipeline in public ways at pressures up to 500 psi (1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 88).

However, in acknowledging the determination of another agency, the Siting Council cannot ignore its responsibility to review issues which may extend beyond the scope of that determination. Here, although the MDPU has issued a decision regarding the engineering design features of the proposed pipeline (see D.P.U. 87-143), the Siting Council retains responsibility for reviewing the compatibility of the proposed pipeline with existing and planned land use and development. This responsibility necessarily includes evaluating the safety of the proposed high pressure pipeline not only in the context of design and engineering features, but also in the context of siting considerations, such as type and density of development along various routes. In fulfilling this responsibility, we are not substituting our judgment for that of the MDPU on engineering issues. On the contrary, an MDPU ruling accepting the pipeline design is a necessary condition for Siting Council approval of a high pressure gas pipeline. Accordingly, we affirm our jurisdiction over safety issues and reject Bay State's contention that the review of safety issues lies exclusively within the jurisdiction of the MDPU.

(B) Description

Bay State argues that the conservative design and the sophisticated safety measures incorporated into the proposed pipeline demonstrate the safety of the pipeline (Bay State Brief, pp. 43-47). MASSPOWER similarly argues that Bay State has incorporated conservative design features into the proposed pipeline, and that Bay State has emphasized safety features since the inception of the project (MASSPOWER Brief, p. 42).

The Company's witness, Mr. LaShoto, provided a detailed description of the safety design features incorporated into the proposed pipeline (Tr. 5, pp. 5-28). Mr. LaShoto explained that the proposed pipeline has been designed to meet federal design standards for a distribution pipeline, which are more stringent than those for a transmission pipeline (Exh. BSG-2). Mr. LaShoto further explained that the proposed pipeline was designed to meet the most strict location standards, Class 4, of the United States Department of Transportation, even though the proposed pipeline does not pass through any Class 4 locations (id., p. 7). In addition to meeting federal design standards, the Company stated that the proposed pipeline has been designed to meet or exceed all requirements of the Massachusetts Gas Distribution Code, 220 CMR 101 (Exhs. BSG-2, p. 6, HO-E-36).

The Company described additional safety design features incorporated into the proposed pipeline, including a supervisory control and data acquisition ("SCADA") system (Exh. HO-SA-6). Mr. LaShoto explained that the SCADA system collects flow and pressure data along the pipeline at approximately eight-second intervals, which it transmits via telephone lines to the Company's Ludlow control center (Tr. 5, pp. 5-6). Mr. LaShoto stated that the SCADA system, upon detecting a high or low pressure or flow situation, would automate alarms in the control center (id., pp. 6-7). Mr. LaShoto indicated that the proposed 500 psi pipeline would include approximately nine or ten SCADA monitoring devices (id., p. 9).

In addition to the SCADA monitoring system, the Company explained that the proposed pipeline design includes numerous valves to be located along the pipeline (Exhs. HO-SA-7, HO-SA-9; Tr. 5, pp. 12-20). Mr. LaShoto stated that a "slam-shut" valve would be located at the Tennessee gate station, which would automatically stop additional natural gas from flowing into the pipeline should the SCADA system detect an unexplained pressure or flow change (Tr. 5, p. 12; Exh. HO-SA-9). Mr. LaShoto further explained that the proposed pipeline would include a sectionalizing valve, located at Bay State's Ludlow LNG facility, which would separate the pipeline into two discrete segments, as well as relief valves, which would vent overpressure in remote locations away from any sources of ignition (id.). Finally, Mr. LaShoto indicated that manually operated valves would be located on both sides of all bridge crossings and at meters from which large customers are served (Tr. 5, p. 15).

The Company also explained that above-ground markers and a below-ground warning tape would be placed along the pipeline to warn excavators of the pipeline (Exh. HO-SA-9; Tr. 5, pp. 24-25). Finally, Bay State argued that the smaller, lower pressure pipeline, which would be installed in the same trench as, and slightly above, the high-pressure pipeline, would act as a shield to protect the high-pressure pipeline because an excavator who ignored the markers and warning tape likely would strike the smaller pipeline before reaching the larger pipeline (Bay State Brief, p. 46).

Bay State offered the testimony of Mr. Long of the Institute of Gas Technology, an industry-sponsored research and education institution (Exh. BSG-3, p. 3). Mr. Long testified that the proposed pipeline is consistent with industry standards, and even exceeds the safety of typical pipelines due to its sophisticated telemetering and valve systems (id., pp. 5-8). Mr. Long also testified that the construction of high-pressure pipelines in public ways is common practice among local distribution companies (id., p. 4).

iii. Analysis

As in the 1990 Berkshire Decision, the fundamental issue regarding land use, traffic and safety which the Siting Council must address in this proceeding is the acceptability and reasonableness of siting a 500 psi pipeline almost entirely within public ways. The Siting Council stated in the 1990 Berkshire Decision that although particular project circumstances at times can warrant siting high pressure gas pipelines longitudinally in public streets, this does not mean that it is appropriate to route such pipelines along streets of all types and for unlimited distances (1990 Berkshire Decision, EFSC 89-29 (Phase II), p. 88).

The Siting Council expects project developers to select routes for high pressure pipelines which accommodate existing land use. Where the function of a high pressure pipeline or physical constraints provide no alternative to placement of the pipeline in densely developed areas, it is reasonable to expect that the developer will incorporate sophisticated and comprehensive safety features into the design of the pipeline.

The Company's stated goal of bringing natural gas service to the greatest number of new customers requires that the proposed pipeline be sited in or near developed areas. Bay State's innovative and comprehensive approach to safety design has resulted in the incorporation of sophisticated safety measures into the proposed pipeline, measures which meet or exceed federal and state design standards. The Siting Council also notes that the MDPU has reviewed the design features of the proposed pipeline, and approved the Company's petition to operate the pipeline at pressures up to 500 psi (with the exception of the Springfield extension to serve MASSPOWER, a petition for which currently is pending before the MDPU).

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, the Palmer Variation, the Ludlow Variation, and the West Avenue Variation is acceptable with respect to land use, traffic and safety.

2. Environmental Impact of the Alternative Route

a. Water and Land Resources

As with the primary route, the Company noted that erosion and sedimentation into streams or wetlands was possible during pipeline construction, especially if it rains during construction (Exh. HO-E-21). The National Wetlands Inventory Maps provided by the Company indicate the presence of numerous wetlands in the vicinity of the alternative route, which is typical for the area and comparable to those along the primary route (Exh. HO-E-22).

With regard to public water supplies, the Company stated that along the alternative route in Hampden, approximately 50 percent of the buildings currently are not served by Town water, and approximately 65 percent currently are not served by the Town sewer system (Exh. HO-E-45). The Company noted that blasting is expected along segments of the alternative route where Town water and sewer service are not available, and thus where wells and septic systems may by located (Exh. HO-E-46). However, the Company noted that this segment of the alternative route is lightly settled, and therefore is not likely to be near a large number of wells or septic systems (id.). Bay State asserted that construction of the proposed pipeline along the alternative route will not have an adverse effect on nearby wells or septic systems (Exh. HO-E-45).

The Company's witness, Mr. Setian, stated that because the alternative route follows less well-defined roads than the state highways used by the primary route, the Company would expect to encounter a greater number of trees along the alternative route than along the primary route (Tr. 5, p. 59). Mr. Setian also noted that tree roots may be located nearer to the surface along portions of the alternative route containing ledge (id.). However, the Company contended that it will construct the pipeline in a manner which minimizes tree impacts (Bay State Brief, pp. 59-60).

As with the primary route, the Company will be able to minimize the impact of construction on wetlands and streams through the use of appropriate erosion control measures. Although wells and septic systems may be located near the segment of the alternative route where blasting is expected, the number of wells or septic systems which could be affected is small. Further, Bay State could test nearby wells before and after construction to detect whether any damage had occurred, and could make appropriate repairs or replacements as necessary. With regard to potential tree impacts, Bay State has demonstrated that appropriate construction techniques would be employed to mitigate any potential impacts.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the alternative route would have an acceptable impact on water and land resources.

b. Land Use, Traffic and Safety

As with the primary route, the alternative route passes through residential, commercial, and industrial zoned areas, although the Company noted the generally more rural features of the alternative route (Exhs. HO-E-1, HO-E-45). The alternative route passes within 15 feet of one residence, and within 50 feet of numerous residences, the majority of which are located along the eight-inch pipeline in Monson and Palmer (Exhs. HO-E-12, HO-E-13). The alternative route passes within one-quarter mile of two schools and a day care center, and within one-half mile of a hospital (Exh. HO-E-3).

The Company indicated that no structures along the alternative route are identified on the National Register of Historic Places (Exh. HO-E-2). The Company also provided a determination from the MHC that construction along the alternative route will not affect significant cultural, historical, or archaeological resources (id.). The record indicates that a number of structures which are included in the MHC inventory of potentially significant structures are located along the segment of the alternative route where blasting is expected (id.; Exh. HO-E-17). However, the Company emphasized that the amount of blasting required to excavate a trench four and one-half feet deep is relatively small (Exh. HO-E-46). The Company's witness, Mr. Long, stated that the type of damage most commonly associated with blasting for pipeline construction is cracked plaster in nearby structures (Tr. 2, pp. 44-45).

The Company stated that one lane of traffic would be open at all times during construction along the alternative route, and that traffic impacts generally would be the same as for the primary route (Exhs. HO-E-5, HO-E-6). Similarly, Bay State indicated that the safety design features of the proposed pipeline would be identical whether the pipeline is constructed along the primary route or alternative route (Exhs. HO-SA-9, HO-E-39).

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the alternative route is acceptable with respect to land use, traffic, and safety.

3. Conclusions on Environmental Impacts

The Siting Council has found that construction of the proposed facilities along the primary route would have an acceptable impact on water and land resources, as well as land use, traffic and safety.

The record demonstrates that the most likely impacts of the primary route on water and land resources would be: (1) potential erosion and sedimentation into nearby streams and wetlands during construction; (2) possible alteration of subsurface drainage patterns caused by the new conduit along the sand padding around the pipeline; and (3) possible alteration of tree root systems following consultation with a certified arborist.

The Ludlow Variation and West Avenue Variation are comparable to the portions of the primary route that they would replace with regard to impacts on water and land resources. The Palmer Variation passes near two potential wetland areas, and may require clearing of some vegetation along the sewer easement right-of-way. However, these potential impacts could be minimized through mitigation measures and appropriate construction techniques. Accordingly, the Palmer Variation is comparable to that portion of the primary route that it would replace with respect to impacts on water and land resources. The alternative route would require blasting in areas where wells and septic systems are likely to be located, and thus could have an impact on water resources.

In sum, the primary route is preferable to the alternative route with respect to impacts on water and land resources. Further, among the variations to the primary route, the Ludlow Variation, West Avenue Variation, and Palmer Variation are comparable to the portions of the primary route which they would replace with respect to impacts on water and land resources.

The record demonstrates that the most significant impact of the primary route on land use, traffic and safety would result from placement of the pipeline in developed residential and commercial areas, which include a number of sensitive receptors and potentially significant historic structures. The Ludlow Variation passes within 50 feet of significantly more residences than the primary route along this segment, and brings the pipeline nearer to an additional three schools. The West Avenue Variation, like the segment of the primary route it would replace, does not pass within 50 feet of any residences or near any sensitive receptors. The Palmer Variation avoids 14,000 feet of continuous residential and commercial development along that portion of the primary route that it would replace, a portion which includes numerous residences within 50 feet of the proposed pipeline and two schools within one-quarter mile of the proposed pipeline. Finally, the alternative route, like the primary route, passes within 50 feet of numerous residences. The alternative route would require blasting in locations near several structures on the MHC's inventory of structures of potential historical significance. Although the MHC has determined that the the construction of the pipeline along the alternative route will not affect significant cultural, historical, of archaeological resources, the Siting Council notes the possibility of damage to historic structures due to blasting.

In sum, the primary route is preferable to the alternative route with respect to impacts on land use, traffic and safety. Further, among the variations to the primary route: (1) the primary route is preferable to the primary route with the Ludlow Variation with respect to impacts on land use, traffic and public safety; (2) the primary route with the West Avenue Variation is comparable to the primary route with respect to impacts on land use, traffic and safety; and (3) the primary route with the Palmer Variation is preferable to the primary route with respect to impacts on land use, traffic and safety.

Based on the foregoing, the Siting Council finds that the primary route is preferable to the alternative route with respect to environmental impacts. Further, in regard to the variations to the primary route, the Siting Council finds that: (1) the primary route is preferable to the primary route with the Ludlow Variation with respect to environmental impacts; (2) the primary route is comparable to the primary route with the West Avenue Variation with respect to environmental impacts; and (3) the primary route with the Palmer Variation is preferable to the primary route with respect to environmental impacts.

F. Reliability

The Company argued that because reliability does not vary among pipeline routes, the proposed pipeline would provide reliable service to new customers along the primary route, the alternative route, and any of the proposed variations (Bay State Brief, p. 52). Bay State also stated that the Company's overall system reliability would be improved by the proposed interconnection with Bay State's existing system at the Ludlow LNG facility, which is included in both the primary and alternative routes (Exh. BSG-1, Schedule BSG-1-1; Bay State Brief, p. 52). MASSPOWER similarly argued that reliability of service does not vary among the primary route, the alternative route, or any of the proposed variations (MASSPOWER Brief, p. 44).

The Company's witness, Mr. Long, testified that the most likely cause of a major leak in any natural gas pipeline, including the proposed pipeline, is third party damage from an excavator who is unaware of the buried pipeline (Exh. BSG-3, p. 6). Mr. Long further stated that third party damage is more likely to occur in a developed area than in one that is isolated, and is particularly likely in areas with a great deal of construction activity, such as those which are in the process of being developed (Tr. 2, pp. 12-14). Mr. Long also noted that danger of third party damage arises more from contractors repairing the sewer or water lines which connect individual customers to the main line than from other utility companies working on their own lines because utility companies have established procedures for locating buried lines (id., pp. 12-13). Mr. Long stated that the segment of Bay State's proposed primary and alternative pipeline routes and variations which is least likely to encounter this type of third party damage is the MTA right-of-way (id., pp. 14-15).

The Company indicated that it had contacted all utility companies likely to own and operate utilities buried in the streets in which Bay State proposes to construct its pipeline (Exh. HO-E-14). The Company provided maps of all underground utility lines in Main Street in Monson and Palmer, two areas where numerous other utilities are buried under the street and where concern had been expressed regarding whether adequate room exists for the proposed pipeline (Exh. HO-E-15). These maps demonstrate that even though these streets are congested with water, sewer and telephone lines, adequate space exists for the proposed pipeline, including the 10-foot separation which the Palmer Water District requested between its water mains and the proposed natural gas pipeline (id.; Exh. HO-E-14).

The record indicates that disruption of natural gas service due to damage to the pipeline is most likely to occur from third party excavation near the pipeline, and that third party excavation is most common in areas of significant construction activity and in areas where contractors may attempt to reach utility lines other than the proposed pipeline. In light of the above, third party damage to the proposed pipeline is more likely in streets congested with other utilities, such as Main Street in Monson and Palmer, than where the proposed pipeline would be placed on a separate right-of-way such as the MTA right-of-way along the primary route and the sewer right-of-way along the Palmer Variation.

Based on the foregoing, the Siting Council finds that the primary route, the alternative route, the Ludlow Variation, the West Avenue Variation and the Palmer Variation are acceptable with respect to reliability.

Further, the Siting Council finds that the primary route is comparable to the alternative route with respect to reliability. Among the variations to the primary route, the Siting Council finds that: (1) the primary route is preferable to the primary route with the Ludlow Variation with respect to reliability; (2) the primary route with the West Avenue Variation is comparable to the primary route with respect to reliability; and (3) the primary route with the Palmer Variation is preferable to the primary route with respect to reliability.

G. Conclusions on the Proposed and Alternative Facilities

The Siting Council has found that the Company considered a reasonable range of practical alternatives.

The Siting Council has found that the primary route is preferable to the alternative route with respect to cost. The Siting Council has found that the primary route is comparable to the primary route with the Ludlow Variation and the primary route with the Palmer Variation with respect to cost.

The Siting Council has found that the primary route, the alternative route, and the primary route with the Ludlow, West Avenue or Palmer Variation are acceptable with respect to environmental impacts. The Siting Council has found that the primary route is preferable to the alternative route with respect to environmental impacts. The Siting Council has found that the primary route is preferable to the primary route with the Ludlow Variation with respect to environmental impacts. The Siting Council has found that the primary route is comparable to the primary route with the West Avenue Variation with respect to environmental impacts. Finally, the Siting Council has found that the primary route with the Palmer Variation is preferable to the primary route with respect to environmental impacts.

The Siting Council has found that the primary route, the alternative route, and the primary route with the Ludlow, West Avenue or Palmer Variation are acceptable with respect to reliability. The Siting Council has found that the primary route is comparable to the alternative route with respect to reliability. The Siting Council has found that the primary route is preferable to the primary route with the Ludlow Variation with respect to reliability. The Siting Council has found that the primary route is comparable to the primary route with the West Avenue Variation with respect to reliability. Finally, the Siting Council has found that the primary route with the Palmer Variation is preferable to the primary route with respect to reliability.

Accordingly, the Siting Council finds that the primary route is, on balance, preferable to the alternative route. The Siting Council finds that the primary route is, on balance, preferable to the primary route with the Ludlow Variation. The Siting Council also finds that the primary route is, on balance, comparable to the primary route with the West Avenue Variation, and the Siting Council notes that the Company has indicated its preference for the West Avenue Variation. The Siting Council further finds that the primary route with the Palmer Variation is, on balance, preferable to the primary route.

Accordingly, the Siting Council approves the primary route with the Palmer Variation and the West Avenue Variation.

However, in order to ensure that the Company's proposal is implemented in a manner consistent with the Siting Council's standard that there be a minimum impact on the environment, the Siting Council ORDERS Bay State to:

(1) in locations where the pipeline would extend along a public way where trees border the route, construct the pipeline either in the roadway or between the trees and the roadway, and follow an alignment that avoids any removal of trees, minimizes any damage to branches, and minimizes construction in locations where roots of one inch or more in diameter may be expected, consistent with public safety needs and reasonable cost and reliability constraints associated with the design, construction and operation of the pipeline;

(2) replace any trees seriously damaged by construction of the pipeline, as determined by the tree warden or other appropriate official, and restore all landscaping, shrubbery and driveways along the pipeline route to pre-construction condition;

(3) repave the portion of streets where excavation for pipeline construction occurs within the street, and repair any potholes or pavement failures that develop as a result of pipeline construction, unless otherwise directed by responsible officials;

(4) perform repairs or reimburse any expenses incurred by property owners to correct any damage to existing utility, water or sewer lines or pipes caused by construction of the pipeline;

(5) after consultation with local conservation commission, public works department, or other appropriate officials, incorporate anti-seepage collars in the design of the

pipeline alignment where necessary to avoid changing subsurface drainage patterns existing prior to construction;

(6) install the proposed pipeline at least twenty feet from all residences and other structures normally occupied by humans, where consistent with reasonable constraints associated with the design, construction, and operation of the pipeline;

(7) in cooperation with appropriate federal, state and local officials, develop appropriate emergency response plans for possible accidents or related contingencies resulting from operation of the 16-inch diameter, 500 psi pipeline, and provide a copy of such plans to the Siting Council prior to operation of the pipeline;

(8) publish emergency response plans and procedures in a brochure to be mailed or delivered to all property owners and residents abutting the route of the 16-inch diameter, 500 psi pipeline, and, if requested, hold public educational forums prior to operation of the pipeline;

(9) implement the pipeline safety features as presented in the record, including: (a) the installation of pipeline warning tape and above-ground markers; (b) the installation of a 24-hour flow monitoring and automatic shut-off valve system; and (c) the performance of regular inspections of the pipeline route to detect any leaks and to monitor construction activity by outside parties; and

(10) make available for public inspection at Bay State's offices a plan of the exact location of the pipeline, indicating the depth of the pipeline and showing locations of abutting property lines and existing utility, water and sewer lines.

IV. DECISION AND ORDER

The Siting Council finds that upon compliance of the MASSPOWER project proponents with the first three conditions set forth in Section II.D of the MASSPOWER Decision,[50, 51] and upon compliance of Bay State with the ten conditions set forth in Section III.G, above, the proposed pipeline facility and ancillary facilities proposed in this proceeding will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, subject to compliance with the above conditions, the Siting Council hereby APPROVES the petition of the Bay State Gas Company to construct an 18.2-mile, 16-inch diameter, natural gas pipeline, with a maximum operating pressure of 500 pounds per square inch, and ancillary facilities thereto, in the City of Springfield and in the Towns of Monson, Palmer, Wilbraham and Ludlow; the pipeline route herein conditionally approved follows the primary route proposed by Bay State, except that the approved route follows the Palmer Variation and the West Avenue Variation rather than the

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50/ The record in this proceeding clearly establishes that service to MASSPOWER is the primary purpose of the pipeline. Therefore, in the absence of service to MASSPOWER, construction of the pipeline is not warranted and commencement of construction must be conditioned upon final approval of MASSPOWER.

51/ See page 66 of the MASSPOWER Decision for the complete text of these conditions. The MASSPOWER Decision also contains a fourth condition requiring approval of the Bay State pipeline proposal in EFSC 89-13 as a prerequisite for commencing construction of the MASSPOWER facility. In issuing our decision in this docket, we acknowledge that this condition has been met.

corresponding sections of the primary route (see Section III, above).

Stephen Klionsky
Hearing Officer

Dated this 12th day of October 1990

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of October 12, 1990 by the members and designees present and eligible to vote. Voting for approval of the Tentative Decision as amended: Paul W. Gromer (Commissioner of Energy Resources); Barbara Kates-Garnick (for Mary Ann Walsh, Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Scott Colby (for John P. DeVillars, Secretary of Environmental Affairs); Sarah Wald (Public Environmental Member); Kenneth Astill (Public Engineering Member); Joseph W. Joyce (Public Labor Member) and Dennis LaCroix (Public Gas Member).

Paul W. Gromer
Chairperson

Dated this 12th day of October 1990

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Rulemaking Regarding the Procedures by Which Additional Resources are Planned Solicited, and Procured by Investor-Owned Electric Companies (Integrated Resource Management)	EFSC 90-RM-100A

FINAL ORDER ON RULEMAKING

Frank P. Pozniak
Hearing Officer
November 30, 1990

On the Decision:

Michael B. Jacobs

Pamela M. Chan
Robert Graham
Robert J. Harrold
Stephen Klionsky
Robert D. Shapiro

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I. INTRODUCTION

On July 5, 1990, the Energy Facilities Siting Council ("Siting Council" or "EFSC") issued an Order and proposed regulations regarding the procedures by which additional resources are planned, solicited, and procured to meet an investor-owned electric company's obligation to provide reliable electric service to ratepayers in a least-cost, least-environmental impact manner.[1] EFSC 90-RM-100 (1990). This comprehensive integrated resource management ("IRM") process requires regulatory review of electric companies' IRM practices by both the Siting Council and the Department in the exercise of each agency's statutory authority. On August 31, 1990, the Department issued an Order and final regulations for its portion of the IRM regulatory framework. D.P.U. 89-239 (1990); 220 CMR 10.00.

In EFSC 90-RM-100, the Siting Council proposed a regulatory structure in which the Siting Council and Department systematically would review the electric companies' forecast of energy need and procurement of resources. The Order issuing the proposed regulations considered such matters as: (1) the framework for settlement negotiations before the electric company's initial filing is made; (2) the time period allotted for the Siting Council's review of the initial filing; (3) the Siting Council's review of the demand forecast; (4) the Siting Council's review of the supply plan, including different approaches for reviewing an electric company's resource inventory; (5) the Siting Council's review of the electric company's estimate of resource need; and (6) the procedure for requiring electric companies to describe the technical potential

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1/ Pursuant to G.L. c. 164, sec. 69H, the Siting Council is responsible for providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Throughout this Order, the Siting Council uses this statutory standard synonymously with the definition of "total cost to society" contained in the Department of Public Utilities' ("Department" or "DPU") regulations at 220 CMR 10.02.

of resources. In its Order, the Siting Council requested comments in each of these areas.

To allow interested persons the opportunity to discuss issues raised by the proposed regulations, two technical sessions were held jointly by the Siting Council and Department on August 7 and August 14, 1990. Following the technical sessions, written comments were received by the Siting Council by August 27, 1990.[2] Public hearings on the proposed regulations were held jointly by the Siting Council and the Department on September 5, 6, and 7, 1990. Additional comments were received after the close of public hearings.[3]

2/ When cited, these comments are referenced as "Comments."

3/ When cited, these comments are referenced as "Final Comments."

II. IRM STRUCTURE

A. Jurisdiction and Scope of Regulations

1. Introduction

Sections 69G and 69H of Chapter 164 of the General Laws require the Siting Council to review the annual demand forecasts and supply plans of electric utilities and to ensure that the Commonwealth is provided with a necessary energy supply at the lowest possible cost with a minimum impact on the environment. The new IRM regulations are intended to operate within this jurisdictional mandate and to coordinate more effectively the Siting Council's and the Department's review processes. Under the regulations, the Siting Council will continue to review an electric company's forecast of demand and the adequacy of supply in the short run. For an electric company subject to these regulations, however, the Siting Council will rely on the Department's findings at the end of the coordinated EFSC/DPU IRM process to determine whether the electric company's supply plan is least-cost and minimizes environmental impact. General Laws, Chapter 164, Section 69Q expressly allows for this type of interagency coordination as a means of achieving the Siting Council's statutory mandate.

Comments received during the course of this proceeding pertained most directly to the scope of the regulations rather than to the jurisdiction of the Siting Council to issue these regulations. Often, however, the comments intertwined the question of jurisdiction with that of the scope of the regulations.

2. Multi-State Investor-Owned Utilities

a. Comments

Two investor-owned utilities ("IOU's") commented on this aspect of the proposed regulations. Massachusetts Electric Company ("MECo") and New England Power Company ("NEPCo") state that MECo provides retail service to customers in Massachusetts, while NEPCo is the all-requirements power supplier of MECo and

MECo's non-Massachusetts retail affiliates (MECo/NEPCo Statement, p. 1).[4] MECo's rates are regulated by the Department and NEPCo's are regulated by the Federal Energy Regulatory Commission ("FERC"). Under G.L. c. 164, sec. 69G, the Siting Council historically has reviewed the demand forecast of MECo and the supply plan of NEPCo. MECo and NEPCo state that because the New England Electric System ("NEES"), their parent company, has separated the operations of its companies along functional lines, the implementation of IRM is different from that of a single vertically integrated company (id., p. 1).

MECo and NEPCo indicate that the proposed regulations should focus on demand-side programs and contracts with Qualifying Facilities ("QFs") in Massachusetts (id., pp. 1-2). MECo and NEPCo further state that, under the Siting Council's present regulations (980 CMR 7.01(5)(b)), the Siting Council reviews a multi-state forecast only when it "serves to justify the construction of facilities in the Commonwealth" (id., p. 2). MECo and NEPCo propose to include within the IRM process those programs and projects that are subject to the Department's and the Siting Council's jurisdiction, but to exclude resources and projects located outside of Massachusetts (id., p. 3). MECo and NEPCo state that these projects are subject to other states' permitting authorities and deference to the policies and regulatory requirements of these other states is appropriate (id., p. 4, MECo/NEPCo Final Comments, p. 16). MECo states that this assertion is consistent with 980 CMR 7.01(5)(b), as well as 980 CMR 7.02(9)(d), 7.04(1)(a) and 7.04(6), which limit the Siting Council's review of demand forecasts to Massachusetts loads and new Massachusetts facilities (MECo/NEPCo Final Comments, p. 17).

Eastern Edison Company ("EECo") and Montaup Electric Company ("Montaup") also submitted comments jointly. EECo serves retail customers in Massachusetts. Montaup is EECo's

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4/ This statement was submitted by MECo and NEPCo immediately before the testimony of its witness at the September 6 hearing.

all-requirements power supplier and is subject to rate regulations by FERC. Both EECo and Montaup are subsidiaries of Eastern Utilities Associates ("EUA") (EECo/Montaup Final Comments, p. 4). EECo and Montaup state that, as components of a multi-jurisdictional power system, they cannot be treated as if they were one utility that carries out its resource planning and procurement only within the confines of Massachusetts (id.).

EECo and Montaup state that EUA recognizes its responsibility to provide a least-cost, least-environmental impact supply of resources but believes that it must make this determination on a system-wide basis as opposed to conducting separate solicitations in each state (id.). EECo and Montaup also state that they "agree with the philosophy of IRM, and intend to voluntarily comply with DPU regulations with regard to [EECo], and with . . . Siting Council regulations [with regard] to [EECo and Montaup], to the extent possible" (id.). They further state, however, that they may request waivers from the IRM rules in certain cases (id.). EECo and Montaup particularly note their concern with the Siting Council's reliance on the Department for review of an electric company's supply plan, as they assert that the Department's regulations are not applicable to Montaup (id.). EECo and Montaup propose that the Siting Council continue its present review of supply plans for multi-jurisdictional utilities, a review that, according to EECo and Montaup, focuses on the process that a company employs in analyzing resource options (id., p. 5).

b. Analysis and Findings

As set forth above, the Siting Council's goal in the development of IRM is to fulfill more efficiently its statutory mandate while coordinating its efforts with the Department. We find that the IRM framework, under which the Siting Council is the lead agency in analyzing an electric company's demand forecast and resource inventory, and the Department is the lead agency in analyzing different resource options offered through an all-resource solicitation, best enables the two agencies to meet this shared goal. We note that most utilities did not comment on the jurisdiction of the Siting Council to promulgate the regulations nor comment on the scope of the regulations.

Here, two multi-jurisdictional electric systems raised questions about the extent of the IRM framework. From the outset, it has been the Siting Council's intention to promulgate regulations which are sufficiently robust to achieve the goals of the IRM process for utilities that operate only in Massachusetts as well as electric companies that operate as part of a multi-state framework. In developing such a robust regulatory model, we certainly recognize that there are some important differences in the electric companies under our jurisdiction, differences that may warrant different treatment for different utilities.

However, the IRM framework is consistent with our present approach under 980 CMR 7.00. Our current regulations do not differentiate between electric companies operating exclusively within Massachusetts and multi-jurisdictional companies. The Siting Council historically has reviewed the demand forecasts and supply plans of electric companies operating only in Massachusetts, such as Fitchburg Gas and Electric Light Company ("Fitchburg") and Boston Edison Company ("BECo"), and electric companies that are part of a multi-jurisdictional framework, such as MECo and NEPCo, and EECo and Montaup. We anticipate that the IRM process similarly will be flexible enough to allow us to review the demand forecasts and supply plans of all electric companies subject to 980 CMR 12.00; under the IRM process, we would use a method different from the present approach -- that is, we would rely on the EFSC/DPU coordinated review of a competitive procurement process -- to review supply plans.

None of the comments received from MECo, NEPCo, EECo or Montaup persuades us that the proposed regulations should be changed to exempt multi-jurisdictional electric companies. First, no commenter has argued directly that the Siting Council has exceeded its jurisdiction in promulgating these regulations.[5] Second, in many respects the Siting Council's review under 980 CMR 12.00 will mirror our review under 980 CMR 7.00 -- a review process which no electric company has contested previously. In regard to demand forecasts, the Siting Council's review will be very nearly identical to our current review under 980 CMR 7.00. In regard to supply plans, the Siting Council always has reviewed the system-wide supply plans of NEPCo and Montaup. The regulations that MECo and NEPCo cite as being inconsistent with a system-wide review are not part of 980 CMR 12.00.

In particular, we reject the argument that 980 CMR 7.01(5)(b) only allows the Siting Council to review a multi-state forecast when a facility is proposed. Our review of a multi-jurisdictional electric company's demand forecast and supply plan has never been performed only to justify facility construction in Massachusetts, but rather to ensure that a demand forecast is reviewable, appropriate, and reliable and that the supply plan is adequate, least-cost, and minimizes environmental impact. See New England Electric System, 18 DOMSC 295 (1989) ("1989 NEES Decision"); Eastern Utilities Associates, 18 DOMSC 73 (1988) ("1988 EUA Decision"); Northeast Utilities, 17 DOMSC 1 (1988) ("1988 NU Decision"); Eastern Utilities Associates, 14 DOMSC 41 (1986) ("1986 EUA Decision"); New England Electric System, 12 DOMSC 197 (1985); Northeast Utilities, 11 DOMSC 1 (1984).

Third, MECo and NEPCo request that the Siting Council continue to defer to the findings of agencies with permitting authority in other states. The Siting Council has no intention of intruding on other states' siting decisions and these rules

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5/ Montaup has indicated that the Department does not have jurisdiction over Montaup's supply planning. The Siting Council does have jurisdiction over Montaup, however (see G.L. c. 164, sec. 69G), and even in the absence of the IRM regulations, could obligate EECo and Montaup as a requirement for Siting Council approval of a forecast and supply plan to engage in a process similar to IRM.

were never intended to raise the possibility of doing such. The Siting Council's review under 980 CMR 12.00 will take into account the siting jurisdiction and decisions of these other states when the supply plan of an electric company is being considered. If utility planning is not done on a single-state basis, a proper regulatory review should recognize this and reflect all relevant information.

Finally, in response to a comment of EECo and Montaup concerning separate solicitations in different states, the Siting Council recognizes that it may be duplicative for a multi-jurisdictional company to engage in separate solicitations in a number of states, and the Siting Council and the Department will work to ensure that no inefficiencies arise in the application of IRM. As we stated above, we recognize that different treatment for different utilities may be warranted under the regulations and we are confident that difficulties can be resolved.[6]

3. Applicability of Rules to Small Electric Companies

In the Siting Council's proposed regulations, Nantucket Electric Company ("Nantucket") was listed as a company to which the IRM regulations would apply. 980 CMR 12.01(2); See EFSC 90-RM-100, p. 7. However, in the Department's final decision in D.P.U. 89-239, Nantucket was excluded from the Department's regulations due to its small size and the fact that it is not connected to the regional power grid (Id., p. 47). The

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6/ In the final IRM regulations, the Siting Council or Department may, where it deems appropriate, consider granting an exception to any provision of those regulations. 980 CMR 12.07(3); 220 CMR 10.07(4). While the IRM process is sufficiently robust to accommodate the special circumstances of multi-jurisdictional electric companies, such companies, for purposes of obtaining a waiver of a particular provision of the IRM regulations, carry the burden of establishing that application of the IRM regulations either conflicts with the laws of other jurisdictions or otherwise impairs the ability of multi-jurisdictional electric companies to meet their responsibilities to ratepayers in Massachusetts and in other states.

Department stated that Nantucket remained subject to a number of existing Department regulations and remained subject to the Siting Council's review of Nantucket's forecast and supply plan.[7] Id. The Siting Council adopts the Department's decision and hereby exempts Nantucket from the application of 980 CMR 12.00. Nantucket remains subject to 980 CMR 7.00.

4. Massachusetts Municipal Wholesale Electric Company

a. Comments

In its Order, the Siting Council did not propose, in general, that the IRM rules be applied to the Massachusetts Municipal Wholesale Electric Company ("MMWEC") or municipal electric companies. EFSC 90-RM-100, p. 7. Instead, the Siting Council requested comments regarding the benefits that MMWEC or its members might receive from participation in the IRM process. Id. Three parties commented on the efficacy of applying IRM or an IRM-like process to MMWEC.

MMWEC contends that it should not be included in IRM, and cannot be included in IRM. It argues that: (1) the Department does not have the general supervisory jurisdiction over MMWEC or its members which would allow the Department to require MMEWEC to participate in the Department's portion of IRM; and (2) the Siting Council cannot force MMWEC and its members to participate in the Department's IRM process (MMWEC Comments, pp. 11-13). Therefore, according to MMWEC, IRM is inapplicable to MMWEC and its members, and the Siting Council must conduct a traditional review of MMWEC's forecast and supply plan (id.).

MMWEC also states that "many aspects of [the IRM] process are embodied in the [Siting Council's] traditional review of an electric company's supply plan" and there is little or no

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7/ The Siting Council currently is reviewing the demand forecast and supply plan of Nantucket. As part of that review, the Siting Council will consider whether Nantucket's supply plan meets the objectives of IRM.

additional benefit to participating in the IRM process (id., pp. 14-15).

MMWEC further states that its member systems are significantly smaller than IOU's and the limited financial and organizational resources require application of a less rigorous standard than embodied in IRM (id., pp. 15-18, MMWEC Final Comments, pp. 6-7). Limited resources, for example, makes it difficult to collect the data or make filings as required by the proposed regulations, according to MMWEC (id.). And, MMWEC states, it is unlikely that any member will construct a generating unit subject to Siting Council jurisdiction (id.).

Finally, MMWEC contends that legal requirements related to the nature of municipal systems and the relationship between MMWEC and municipal systems "limit the ability to solicit alternative supply resources" (MMWEC Final Comments, p. 8).

The Conservation Law Foundation of New England, Inc. ("CLF") supports the application of IRM to MMWEC and contends that events in the past decade have demonstrated that public power entities face many of the same risks as IOU's, and the market-based solution of an IRM scheme could be of equal benefit (CLF Final Comments, p. 4). In addition, CLF contends that the reasons set forth by MMWEC for exemption from IRM -- "the size and limited planning capabilities of the MMWEC member towns [and] the ad hoc and loose nature of the MMWEC affiliation" -- are precisely the reasons MMWEC members could benefit from a resource solicitation in the IRM review process (id.).

The Massachusetts Public Interest Research Group ("MASSPIRG") states that MMWEC should be subject to the same IRM requirements and process as the IOU's (MASSPIRG Comments, p. 1, MASSPIRG Final Comments, p. 1). MASSPIRG also states that questions have been raised about the cost-effectiveness to MMWEC ratepayers of MMWEC's involvement in at least one project, for which the Department denied financing approval, and that from a societal perspective, exempting MMWEC from IRM likely would lead to suboptimal investments (id.)

b. Analysis and Findings

The Siting Council agrees with CLF and MASSPIRG that MMWEC and its member systems would benefit from participation in IRM or an IRM-like process. Municipal electric systems, like IOU's, are charged with the responsibility of procuring energy resources that are least-cost with the least-environmental impact. In addition, because municipal systems sometimes are limited in resources, they might benefit greatly from an all-resource solicitation.[8] This would be the case whether or not MMWEC as a system or any member ever proposed constructing a generating unit subject to Siting Council jurisdiction. There may be a great many cost-effective, least-environmental-impact resources that would come to light as a result of an all-resource solicitation -- such as conservation and load management ("C&LM") measures or generation options -- that are not subject to Siting Council facility review.

The Department has not included MMWEC in its IRM regulations. Similarly, the Siting Council declines to apply 980 CMR 12.00 to MMWEC or other municipal utilities. However, the Siting Council does have substantial jurisdiction over MMWEC and the municipal electric companies and, in the future, will consider whether to impose its own IRM-like process on MMWEC and the municipal electric companies. See Tr. 3, p. 8.

8/ In noting that individual municipal electric companies may be limited in resources, the Siting Council also notes that MMWEC's structure is designed to assist municipal electric companies to overcome the difficulties arising from their limited resources. In this respect, if any aspect of the nature of the relationship between MMWEC and the municipal electric companies limits the municipals' ability to solicit alternative energy sources, it is the responsibility of MMWEC and the municipals to resolve problems so that municipals are not placed at any disadvantage in procuring least-cost resources.

B. Pre-Initial Filing Settlement Process

In its Order and proposed regulations, the Siting Council proposed the use of a pre-initial filing settlement process involving technical sessions and settlement negotiations as an effective means of helping to resolve as many issues as possible concerning the initial filing. EFSC 90-RM-100, pp. 8-9, 16-17; 980 CMR 12.03(3) and (4). As proposed, the pre-initial filing settlement process would begin when the EFSC and Department issued a joint Order of Notice, 11 weeks before the initial filing date. The joint Order of Notice would inform the public of the electric company's draft initial filing, technical sessions, and initial filing. Within ten days from the issuance of the joint Order of Notice, the electric company would publish the notice in at least one newspaper of general circulation in its service territory,[9] as approved by the EFSC and the Department, and send written notice to any person that had filed a request for notice with the electric company. At the time the joint Order of Notice was published, the electric company would submit to the EFSC and the Department its draft initial filing. Any person who wished to intervene as a party would file a written request to the EFSC and/or the Department for such status within ten business days of the publication of the joint Order of Notice. In addition, any person who wished to participate as an interested person would file a written request to the EFSC within ten business days of the publication of the joint Order of Notice.

The Department's final regulations at 220 CMR 10.03(3)(a) set forth a slightly different procedure than that set forth in the Siting Council's proposed regulations.[10] In the

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9/ The electric company would be notified by the EFSC and Department of the latest date of publication for the joint Order of Notice.

10/ The procedure in the Department's final regulations also differs from that set forth in the Department's proposed regulations.

Department's final regulations, the electric company would submit the draft initial filing to the Siting Council and Department at the beginning of the IRM process or 11 weeks before the initial filing date, and not ten days after the issuance of the joint Order of Notice as set forth in the EFSC's proposed regulations. Thereafter, the procedure outlined above would remain the same.

The procedural change set forth in the Department's final regulations would allow the Siting Council, Department, and the parties to the proceeding additional time to review the draft initial filing without extending the time period for review in Phase I of the IRM process. The Siting Council finds this change to be appropriate. In addition, to inform fully the public about the opportunity to intervene as a party or participate as an interested person in a proceeding, the Siting Council also finds it appropriate to include in the joint Order of Notice deadlines for requests to intervene or participate. Accordingly, the Siting Council's final regulations require that (1) the electric company submit its draft initial filing to the EFSC and Department 11 weeks before the date of the initial filing, at the same time the Siting Council and Department issue a joint Order of Notice, and (2) the joint Order of Notice inform the public about deadlines for requesting to intervene or participate.

Under our proposed regulations and in the Department's final regulations as well, the electric company must hold at least one technical session no less than eight weeks before the initial filing date (1) to explain and clarify the draft initial filing, and (2) to establish procedures and rules for the settlement negotiations. Any settlement, partial settlement, or contested settlement reached by all or some of the parties would be filed as part of the initial filing. The EFSC and Department would review the settlement, and non-signatory parties to the proceeding would have the opportunity to address any issue included in it. Staff members of the EFSC and Department may participate in settlement negotiations, but such staff members would not participate in the EFSC's or Department's review of the electric company's initial filing, or in other matters directly related to that review.

In addition, under the proposed regulations at 980 CMR 12.03(4)(c), the parties to the proceeding are encouraged to use independent, professional facilitators in the pre-initial filing settlement process. Under the same section of the proposed regulations and in the Department's final regulations at 220 CMR 10.03(4)(c), the staff of the Siting Council and Department may act as facilitators.

Commenters generally agreed that a pre-initial filing settlement phase was appropriate. For instance, Western Massachusetts Electric Company ("WMECo")[11] asserts that the pre-initial filing settlement process could streamline and reduce significantly the litigation in the remainder of the IRM process (WMECo Comments, p. 7). MECo and NEPCo assert that:

> The proposed procedure for presettlement negotiation is a workable and valuable step in the process. It allows parties early and complete access to the information included in the filing at a time that fosters technical discussions and issue resolution. We believe that the settlement process can produce an array of beneficial effects ranging from global resolutions to agreements on the specific issues that require full litigation.

MECo/NEPCo Final Comments, p. 18.

However, a few commenters were concerned that some parties might be left out of the pre-initial filing settlement process. Both MASSPIRG and the Division of Energy Resources ("DOER") stress that it is essential that all parties be invited to participate, and have the opportunity to participate in settlement negotiations (MASSPIRG Comments, p. 1; DOER Comments, pp. 1-2).

11/ The Siting Council notes that Northeast Utilities ("NU"), the holding company that owns WMECo and provides system-wide supply planning for WMECo and other affiliates, is affected by the Siting Council's final regulations.

Clearly, once a petition to intervene as a party to the proceeding has been granted by the Siting Council and Department, that intervenor has the right to participate in the pre-initial filing settlement process. During the course of the pre-initial filing period, intervenors will be notified of the technical session(s) and subsequent settlement negotiations. It is the responsibility of each intervenor to attend and participate in the technical session(s) and settlement negotiations. However, intervenors are not required to participate in the pre-initial filing settlement process and need not agree to any settlements reached in that process. Under the regulations, the adjudicatory process commencing with Phase I will remain open to all intervenors, thus preventing foreclosure of important issues.

The Siting Council also received comments on other aspects of the pre-initial filing settlement process. BECo asserts that the host electric company should be afforded the opportunity to structure the technical sessions and settlement negotiations and establish an agenda with firm time schedules (BECo Comments, p. 4). BECo further argues that the electric company is in the best position to structure the sessions and negotiations and set the agenda because it has the most technical knowledge of the forecast and the existing resource mix, and has the responsibility for the resource plan that will result from the IRM process (id., pp. 4-5). Contrary to BECo's position, DOER asserts that the EFSC and Department should set the initial agenda, but notes that, if all parties are able to reach an agreement on the agenda, the EFSC or Department should be open to requests to amend the agenda (DOER Comments, p. 2).

In addition, WMECo suggests that the staff of the Siting Council and Department be required to participate in the settlement negotiations (WMECo Comments, p. 8).[12] WMECo

12/ The Siting Council's proposed regulations at 980 CMR 12.03(4)(b)(5) and the Department's final regulations at 220 CMR 10.03(4)(b)(5) provide that the Siting Council and Department staff may participate in the settlement negotiations.

asserts that the Siting Council and Department staff will lend guidance on key issues and confine settlement negotiations to only those relevant issues that pertain to the IRM process (id.). SESCO, Inc. also asserts that participation by the Siting Council and Department staff would be extremely valuable in reaching settlements (SESCO Comments, p. 6).

Under the final regulations, the electric company is required to hold at least one technical session at least eight weeks before the initial filing date established by the EFSC and the Department for the purpose of providing a basis for the exchange of information and clarification of the electric company's draft initial filing. 980 CMR 12.03(4)(a). We agree with BECo that, as part of its responsibility to conduct a technical session, it would be appropriate for an electric company to establish an agenda for the discussion of the draft initial filing. This agenda should be submitted with the draft initial filing.

A second purpose of the technical session(s) is to establish procedures or rules designed to limit or settle issues. 980 CMR 12.03(4)(a). Here, the Siting Council does not agree with BECo that the host electric company alone should establish procedures or rules for the settlement negotiations. Instead, the procedures or rules for the settlement negotiations should be established at the technical session(s) by the host electric company and the intervenors.[13] In this manner, all intervenors in the proceeding would be afforded the same opportunity to decide the issues that potentially could be limited or settled. In addition, we expect that facilitators would ensure that the process to establish procedures or rules for the settlement negotiations is carried out in a reasonable and sensible manner.

Finally, with respect to the staff of the Siting Council and Department participating in the settlement negotiations, we

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13/ The Siting Council and the Department expect that decisions on the requests to intervene will be made before the technical session(s).

expect that the staff of the Siting Council and Department would participate actively. In fact, in all likelihood, separate teams of Siting Council and Department staff would be assigned to the settlement negotiations in each proceeding.

In sum, the Siting Council's final regulations require that the electric company submit its draft initial filing to the EFSC and Department 11 weeks before the date of the initial filing. In addition, the final regulations require that the Order of Notice include the intervention and participation deadline date. The remainder of the pre-initial filing settlement process proposed in EFSC 90-RM-100 is not changed in these final regulations.

C. Demand Forecast

1. Filing Requirements and Standard of Review

The demand forecast filing requirements set forth in the proposed regulations at 980 CMR 12.03(5) are essentially the same as those contained in the Siting Council's current regulations at 980 CMR 7.03. In addition to these current filing requirements, the proposed regulations at 980 CMR 12.03(5)(b)(2) would require the electric company to include natural C&LM and fuel switching in its projections of demand for electricity. See Sections II.C.3. and II.F.2.b, below, for discussion of these issues. Under the proposed regulations, the electric company also would be required to include, in addition to its base case scenario forecast, scenario forecasts for high load growth and low load growth. 980 CMR 12.05(5)(e)(2).

Overall, the comments received regarding the proposed demand forecast filing requirements were favorable. WMECo asserts that the proposed regulations correctly recognize that an acceptable demand forecast must have a modeling structure that thoroughly explains the cause and effect relationship of electric consumption (WMECo Comments, pp. 8-9). WMECo also asserts that the proposed regulations implicitly recognize that models and forecasts are a function of the available data and anticipated trends in electric usage patterns as well as the economy of the service territory (id., p. 9). In sum, WMECo states that the proposed regulations correctly define "the tools of the trade" that utility forecasters must use to arrive at reliable estimates of peak load and energy requirements (id.).

WMECo and MASSPIRG support the requirement of high- and low-load growth forecasts (WMECo Comments, pp. 10-11; MASSPIRG Comments, p. 2). WMECo argues that any resource plan which is narrowly based on a single reference forecast will be inadequate (WMECo Comments, p. 11). MASSPIRG asserts that it is important that a utility also have appropriate contingency plans to respond as effectively as possible to various foreseeable scenarios (MASSPIRG Comments, p. 2).

With respect to the forecasts for each customer class, SESCO argues that the residential class should be further disaggregated into single/multifamily, individual/master metered, owned/rented, income levels, geographic divisions, and major rate/revenue codes (SESCO Comments, p. 7). However, EECo and Montaup do not support further disaggregation of the residential class and the commercial class, and in fact, they have concerns with the level of disaggregation required in the proposed regulations (EECo/Montaup Final Comments, pp. 12-14). EECo and Montaup maintain that the level of disaggregation of each customer class should differ depending on the electric company (id., p. 13). EECo and Montaup also maintain that the regulations should require (1) the commercial class to be disaggregated by building or business type, and not by two-digit Standard Industrial Classification ("SIC") code, and (2) the industrial class to be disaggregated by two-digit SIC code or grouping of SIC codes, and not by end-use (id., pp. 12-13).

In addition, EECo and Montaup argue that there is no evidence that highly disaggregated end-use forecasts are more reliable than more aggregated econometric forecasts (id., p. 14). EECo and Montaup maintain that the Siting Council should be careful about requiring ever-increasing amounts of detail and, at least, should be open to arguments about simplifying methodology (id.).

We agree with EECo and Montaup that the commercial class generally should be identified by building type. We also agree with EECo and Montaup that the industrial class generally should be identified by two-digit SIC code or grouping of SIC codes. Such identification of the commercial and industrial classes is consistent with recent EFSC forecast review decisions. 1989 NEES Decision, 18 DOMSC at 310-326; Boston Edison Company, 18 DOMSC 201, 218-220 (1989) ("1989 BECo Decision"). Therefore, consistent with Siting Council precedent, EECo's and Montaup's position on these two matters is reflected in the final regulations.

However, while the level of disaggregation may vary for different electric companies, the Siting Council will continue to encourage all electric companies to develop disaggregated, end-use forecasts. In fact, we note that most electric companies in the Commonwealth, including EECo, employ end-use methodologies to forecast demand in residential and commercial customer classes. See 1989 NEES Decision, 18 DOMSC at 305-322; 1989 BECo Decision, 18 DOMSC at 217-219; 1988 EUA Decision, 18 DOMSC at 84-88. In previous decisions, the Siting Council has encouraged use of commercial forecasting methodologies which employed more end-use specific data, and criticized those methodologies which were too highly aggregated. 1988 EUA Decision, 18 DOMSC at 90-91; Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 106-107 (1987); 1986 EUA Decision, 14 DOMSC at 63-65, 72.

Currently, disaggregated end-use forecasts represent state-of-the-art forecasting techniques which provide several advantages over other forecasting models. These advantages include the capability to model C&LM and to incorporate appliance efficiency standards. As a result, we can not agree with EUA's position that disaggregated, end-use forecasts are not any more reliable than more aggregated, econometric forecasts (EECo/Montaup Final Comments, p. 14). Indeed, EECo's and Montaup's position has not been supported by any of the recent forecasts filed by electric companies, including that of EECo, which continue to employ and further develop disaggregated end-use forecasting models.

Accordingly, except for requiring an electric company to identify the commercial class by building type and the industrial class by SIC code or grouping of SIC codes, the filing requirements proposed in EFSC 90-RM-100 are not changed in the final regulations.

Under the final regulations, the Siting Council's standard of review for an electric company's demand forecast remains the same as at present. The electric company is required to demonstrate that the demand forecast is reviewable, appropriate, and reliable. The Siting Council may approve or reject a demand forecast. In approving a forecast, the Siting Council may find that a particular forecast contained therein (e.g., commercial forecast) is not reviewable, appropriate, or reliable. In addition, under the final IRM regulations, electric companies remain under the obligation to continue to improve their demand forecasts using substantially accurate historical information and reasonable statistical projection methods that employ state-of-the-art forecasting techniques. 980 CMR 12.03(5); See G.L. c. 164, sec. 69J. For example, as mentioned above, many of the electric companies employ sophisticated end-use models in forecasting residential and commercial demand, and we expect all electric companies subject to IRM to continue to develop or improve their end-use models. Further, we expect electric companies to continue to use and develop territory-specific data in their demand forecasts, and to further develop their peak load forecasting techniques.

2. Unacceptable Demand Forecast

a. Background

One of the Siting Council's primary responsibilities in the IRM process is to determine the electric company's resource need to be met through IRM's comprehensive procurement process. Because of this responsibility, the Siting Council's proposed regulations anticipated adjustments or modifications to an electric company's demand forecast in cases where the Siting Council rejected a demand forecast, or where a particular forecast contained therein is found by the Siting Council not to be reviewable, appropriate, or reliable. 980 CMR 12.03(5)(a); See EFSC 90-RM-100, pp. 11-12, 20-22. In this way, the Siting Council had proposed to allow the IRM process to proceed in those cases where the demand forecast has been entirely or partially rejected.[14] The Siting Council also proposed that in cases where the Siting Council needed to modify or adjust a demand forecast, such adjustment or modification would be based either on historical load growth rates, or on statistical projection methods that are appropriate for a company of the size and resources of the electric company, or some other appropriate method. EFSC 90-RM-100, pp. 21-22.

In its Order, the Siting Council requested comments on this proposed approach or, in the alternative, on an approach that would delay the acquisition of resource proposals until an amended demand forecast were prepared and approved. Id., p. 21. In addition, the Siting Council requested comments on the appropriate method to make the adjustment or modification to the demand forecast. Id., p. 22.

b. Comments

Some of the commenters assert that a forecast rejection should not stay the IRM process. MASSPIRG asserts that it may be appropriate to allow the IRM process to proceed to Phase II in some cases where the degree of forecast error is immaterial to the size and type of Phase II solicitation (MASSPIRG Comments, p. 2). However, MASSPIRG contends that it is critical that a presumption not be established that the IRM process will proceed in all cases involving a forecast rejection (id.). Commonwealth Electric Company ("CECo") and Cambridge Electric Light Company ("CELCo") assert that if problems with the demand forecast are minor, then the IRM process should be continued based on a minimum requirement for new resources (CECo/CELCo Final Comments, p. 3). WMECo asserts that if there is an urgent

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14/ We note that pursuant to G.L. c. 164, sec. 69I, an electric company cannot commence construction of a facility unless the facility is consistent with an approved forecast.

need for additional resources, a forecast rejection should not stay the IRM process (WMECo Comments, p. 12).

Both BECo, CECo and CELCo assert that alternative demand forecasts may be generated during the course of a proceeding by changing the assumptions contained in the demand forecast (BECo Comments, pp. 8-9; CECo/CELCo Final Comments, p. 3). BECo, CECo, and CELCo assert that, in this way, the IRM process could proceed and a rejected forecast may be avoided (id.). WMECo asserts that high- or low-load growth forecasts could be used instead of the base case forecast (WMECo Comments, p. 12).

Most commenters assert that the Siting Council should not adjust or modify the demand forecast (id.; MECo/NEPCo Final Comments, p. 21; CECo/CELCo Final Comments, p. 3; MASSPIRG Comments, p. 3). CECo and CELCo maintain that, since it is the electric company's "obligation to serve," the Siting Council should not adjust or modify an electric company's forecast without that company's agreement (CECo/CELCo Final Comments, p. 3). MECo and NEPCo argue that the Siting Council has no statutory authority to adjust or modify the demand forecast (MECo/NEPCo Final Comments, p. 20). In fact, MECo and NEPCo assert that the Siting Council should allow the IRM process to proceed by approving the electric company's own estimate of resource need subject to the condition that the electric company fix the flaw in the demand forecast (id., p. 21). MECo and NEPCo also suggest that the resource need may be adjusted depending on the correction to the demand forecast (id.).

Some commenters assert that, if the Siting Council should determine it necessary to adjust or modify a demand forecast, such adjustment or modification should not be made using either historical load growth rates or statistical projection methods (id.; WMECo Comments, p 12; CECo/CELCo Final Comments, p. 3; MASSPIRG Comments, p. 3). These same commenters assert that adjusting or modifying a demand forecast with historical load growth rates or statistical projection methods will not improve the reliability of the forecast (id.).

Finally, some commenters assert that, if the forecasting process is so deficient and unreliable, then the IRM process should be stayed to afford the electric company the opportunity to address such deficiencies (MECo/NEPCo Final Comments, p. 20; BECo Comments, pp. 8-9; MASSPIRG Comments, p. 2; DOER Comments, p. 3).

c. Analysis and Findings

Clearly, in situations where the Siting Council finds the entire demand forecast and all forecasts contained therein to be reviewable, appropriate, and reliable, the IRM process will proceed in Phase II. However, in those cases where a demand forecast contains deficiencies, or in those rare cases where the demand forecast is grossly deficient, the Siting Council is faced with a more difficult task.

In situations where there are deficiencies in the assumptions or data inputs that are part of a demand forecast, the Siting Council anticipates that, during the course of a proceeding, it may analyze the electric company's high- and low-load growth forecasts, and request the electric company to generate alternative forecasts, to ascertain whether these are more acceptable forecasts of the electric company's need. This approach may allow the Siting Council to find that a forecast is minimally acceptable for purposes of allowing the IRM process to go forward, but a rejection of the forecast nonetheless may be warranted. In addition, there may be instances in which the elements of an electric company's forecast methodology are deficient. In this case, the Siting Council would endeavor to determine a marginally acceptable forecast for purposes of allowing the IRM process to proceed, but a rejection again may be warranted.

Our interest in allowing the IRM process to proceed should not be viewed as a diminution of our commitment to encourage improved demand forecasting. Under our statute and the final regulations, electric companies continue to have an obligation to base their forecasts on substantially accurate historical information and reasonable statistical projection methods that use state-of-the-art forecasting techniques. G.L. c. 164, sec. 69J; 980 CMR 12.03(5).

In the rare cases where the demand forecast is grossly deficient, and where it is not clear that there is a need for additional resources, the Siting Council may stay the proceeding in order to request additional information or require the electric company to submit a new demand forecast. In those rare cases where the demand forecast is grossly deficient, and where it is clear that there is a need for additional resources, the Siting Council finds that it is appropriate to make determinations regarding the demand forecast which will enable the Siting Council to provide the Department with an estimate of the electric company's resource need to be used in the electric company's RFP and in Phase II.

The Siting Council emphasizes that it does not anticipate encountering grossly deficient demand forecasts. Significantly, in recent decisions, the Siting Council has not rejected a demand forecast, although in some decisions we have found some portions of forecasts not to be reviewable, appropriate, and reliable. Massachusetts Municipal Wholesale Electric Company, EFSC 88-1, pp. 10-36 (1990) ("1990 MMWEC Decision"); 1989 NEES Decision, 18 DOMSC at 302-335; 1989 BECo Decision, 18 DOMSC at 208-223; 1988 EUA Decision, 18 DOMSC at 79-97; 1988 NU Decision, 17 DOMSC at 3-18. We expect that, in the future, electric companies will continue to base their forecasts on accurate historical information and reasonable statistical projection methods that use state-of-the-art forecasting techniques.

In reaching our findings above, the Siting Council has carefully considered the arguments of the various electric companies. However, for the following reasons, we cannot accept MECo's and NEPCo's proposal under which the Siting Council would approve the electric company's own estimate of resource need subject to the condition that the electric company fix the flaw in the demand forecast. First, we agree with MASSPIRG that this procedure creates the presumption that the IRM process will automatically proceed to Phase II irrespective of forecast acceptance, and provides no incentive for the electric company to improve its forecasting techniques. Indeed, MECo's and

NEPCo's approach minimizes the importance of good forecasting techniques by allowing electric companies to defer filing acceptable forecasts. Second, there is simply no certainty that the forecast deficiency can be corrected within the IRM cycle, and even if it could, there is a potential that the IRM process would need to be extended if such correction resulted in a different resource need. For example, a different resource need may require the electric company to issue a new or revised RFP which the Department would have to approve in Phase I. As a result, the IRM process effectively might have to start over.

In addition, the Siting Council does not agree with MECo's and NEPCo's argument that the Siting Council has no statutory authority to adjust or modify a forecast. The Siting Council's broad statutory authority under G.L. c. 164, sec. 69H, which charges the Siting Council with the responsibility to ensure a necessary energy supply, effectively allows the Siting Council to adjust or modify a forecast for the purpose of advising the Department of the characteristics and estimates of resource need that should be used in the IRM resource solicitation and procurement processes. The Siting Council also does not agree with CECo's and CELCo's argument that the Siting Council would be usurping the electric company's obligation to serve if it adjusts or modifies an electric company's forecast for the purposes of the IRM process. In cases where a demand forecast is grossly deficient, the electric company has not met its statutory responsibility since it has failed to develop a reviewable, appropriate and reliable forecast. Under our mandate to "ensure a necessary energy supply for the Commonwealth" (G.L. c. 164, sec. 69H), such failure effectively places the responsibility of determining the electric company's estimate of resource need with the Siting Council for purposes of the IRM process.

Nonetheless, we agree with the commenters that adjusting or modifying the demand forecast with historical load growth rates or statistical projection methods may not result in a reliable forecast. As a result, the Siting Council's determinations on the demand forecast and subsequent modifications and adjustments to the resource need will be developed on a case-by-case basis.

Accordingly, based on the above, the review process proposed in EFSC 90-RM-100 is not changed in the final regulations; however, the final regulations do reflect the Siting Council's authority to stay the IRM process.

3. Natural C&LM and Fuel Switching

a. Background

In its proposed regulations, the Siting Council requires that an electric company's projections of demand for electricity include natural C&LM. 980 CMR 12.03(5)(b)(2). Natural C&LM is defined in the proposed regulations as "C&LM that will occur without intervention of the electric company either as a direct supplier or as a purchaser of third party C&LM services." 980 CMR 12.02. The Siting Council's proposed regulations specifically require electric companies to: (1) quantify the effects of natural C&LM as a major determinant of demand, and include the effects of natural C&LM on demand; and (2) separately identify the following types of natural C&LM, which are included in the demand forecast: (a) C&LM programs sponsored or mandated by federal, state and local governments (e.g., building codes and appliance efficiency standards); (b) market-induced C&LM; and (c) market-induced self-generation (excluding sales to the company). 980 CMR 12.03(5)(b)(2). The Siting Council's proposed regulations also require that an electric company's projections of electricity demand include estimates of the substitution of alternative fuels for electricity. Id. In EFSC 90-RM-100, the Siting Council requested responses to the following questions: (1) How precisely can the impact of natural C&LM and fuel substitution on demand be estimated; and (2) Should fuel substitution be treated separately from natural C&LM or is it, in fact, natural C&LM (p. 20).

b. Comments

MECo and NEPCo, EECo and Montaup, WMECo, BECo, DOER and MASSPIRG provided written comments to the Siting Council on the subject of natural C&LM and fuel substitution. MECo and NEPCo maintain that "sound forecasting suggests that [natural C&LM and fuel switching] should be reflected in the utility's sales projections" in order to avoid the potential for seriously overstating the demand forecast (MECo/NEPCo Final Comments, p. 22). MECo and NEPCo assert that "fuel switching is not by definition natural C&LM" (id.). According to MECo and NEPCo, "natural C&LM is caused by customers installing, on their own initiative, measures designed to allow them to use electricity more efficiently and to receive the same electric service at a lower total cost" (id.). MECo and NEPCo argue that fuel switching, in contrast, focuses on market share and customer fuel choice, and consequently that fuel switching and natural C&LM are affected by different factors in the economy and market and so should be modeled separately in any forecast (id.).

EECo and Montaup state that fuel substitution can be subdivided into two categories: "natural fuel substitution" and fuel substitution induced by regulated electric and gas utilities (EECo/Montaup Final Comments, p. 10). Natural fuel substitution, according to EECo and Montaup, is part of the Siting Council's definition of natural C&LM (id.). EECo and Montaup see a distinction, however, between natural C&LM and natural fuel substitution in that the latter generally refers to equipment choice where competing fuels are present, whereas "natural C&LM generally refers to actions which affect average use" (id.).

EECo and Montaup argue that the Siting Council's proposed filing requirements for natural C&LM and fuel substitution, outlined in Section II.C.3.a, above, "should be deleted because they require the expenditure of more resources without increasing the extent to which [a] forecast is reviewable, appropriate and reliable" (id., p. 11). EECo and Montaup state that the "Siting Council should continue to require that these effects be considered as a determinant of demand, as in [980]

CMR 12.03(5)(c)(1)" and that the Siting Council can then review whether these effects have been accounted for in a manner which is appropriate in light of company size (id.).

WMECo states that "natural C&LM is already explicitly recognized in credible forecast assumptions" and that the requirement to explicitly delineate natural C&LM would have "no material impact on peak demand and energy requirement forecasting or forecast accuracy; however, it may be of some assistance in understanding and reviewing utility forecasts" (WMECo Comments, pp. 9-10). WMECo proceeds to suggest a definition of natural C&LM which excludes fuel substitution and self-generation, stating that these "are not natural conservation, rather they are a price response" (id.).

BECo states that its existing demand forecast methodology already includes the effects of naturally occurring C&LM and fuel switching (BECo Comments, pp. 6-7). DOER states that "both natural C&LM and fuel substitution are important forecasting and planning matters" (DOER Comments, p. 3). DOER further states that in order to assess the impact of fuel substitution on demand, the Siting Council will have to examine all pertinent utility fuel substitution programs (id., p. 4). MASSPIRG states that "demand forecasts should be based on disaggregated end-use methodologies to the greatest extent possible" and therefore that it would "generally be appropriate to examine potential fuel substitution for various end-uses" (MASSPIRG Comments, p. 2).

c. Analysis and Findings

As part of its traditional review of an electric company's demand forecast, the Siting Council evaluates whether the utility's inputs and methodologies for considering natural C&LM and fuel switching result in an appropriate and reliable forecast. The Siting Council agrees with WMECo that the provision of quantified estimates of the effects of natural C&LM potentially would be helpful in understanding and reviewing electric companies' demand forecasts. Moreover, the Siting Council expects that the provision of such information will not be overly burdensome to the electric companies. As MECo and NEPCo suggest, the effects of natural C&LM and fuel switching already should be incorporated in any sound demand forecasting methodology. Thus, most electric utilities should not need to make any significant methodological changes to produce such information. For those electric companies whose forecasts do not presently separate out the effects of natural C&LM and fuel switching, our new requirement will focus attention on this important determinant of demand.

Based on the above, we find that natural C&LM and natural fuel switching should be included explicitly in electric companies' demand forecasts. Further, we expect that electric companies will utilize distinct and separate methodologies for incorporating in their demand forecasts the effects of (1) natural C&LM excluding natural fuel switching, and (2) natural fuel switching. We note that this is consistent with our findings in Section II.G.2, below.

Accordingly, the filing requirements relating to natural C&LM and fuel switching proposed in EFSC 90-RM-100 are not changed in the final regulations.

D. Committed Resources

1. Background

In EFSC 90-RM-100, the Siting Council proposed rules which would require electric companies to identify all planned supply-side and C&LM resources and all existing supply-side and C&LM resources that the electric company proposes to be "committed" (p. 25). A committed resource was defined as a resource which is not subject to competition in the all-resource solicitation in Phase II of IRM.

For planned resources, the Siting Council envisioned eliminating as a committed resource certain projects that had not met development milestones. Id., p. 27. Under the proposed rules, the Siting Council also required electric companies to apply an attrition factor to its entire inventory of planned resources.[15] 980 CMR 12.03(7)(a).

The Siting Council further stated that it would review existing supply-side resources to determine whether they have operated at acceptable performance levels and review existing C&LM resources to determine if they have achieved expected annual energy and capacity savings. EFSC 90-RM-100, p. 28. However, the Siting Council noted that generally the review of existing resources would not be comprehensive, except in highly unusual cases, such as when a generating unit has experienced an extraordinarily prolonged outage. Thus, the Siting Council indicated that its review would be consistent with the standard set forth in the 1989 BECo Decision in which the Siting Council stated it would review the operation of a resource to ascertain whether it should still be considered committed only in those cases where "extraordinary circumstances" exist. Id.; 1989 BECo Decision, 18 DOMSC at 255.

The Siting Council also set forth two alternative methods for reviewing existing and planned resources. The first alternative involved subjecting all of an electric company's existing and planned resources to competition, and the other involved subjecting to competition only those resources that had been operating for five years or longer. EFSC 90-RM-100, p. 30.

Subsequent to the Siting Council's Order in EFSC 90-RM-100, the Department, on August 31, 1990, issued its final IRM rules. In the Department's Order accompanying these final IRM rules, the Department discussed committed resources, albeit recognizing that the issue is appropriately the subject of the EFSC's IRM regulations. D.P.U. 89-239, pp. 11-12. The Department stated that it understood an existing resource would be treated as committed unless: (1) a company persuasively made the case that an existing resource should not be committed (i.e., it should be replaced); or (2) the Siting Council

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15/ In this Order, attrition is discussed separately from committed resources. See Section II.E, below.

determined that the cost, performance, environmental, or other characteristics of an existing resource warranted requiring a utility to subject the resource to the all-resource solicitation in Phase II of IRM. Id., pp. 13-14. The Department emphasized that if any generating facility or resource option were replaced in Phase II, then the utility or third-party developer would be fully compensated for the unavoidable or sunk costs of the replaced resource. Id., pp. 15-16. The Department stated that such a framework would eliminate any financial losses by an electric company or third party developer and that it expected that it would be a rare occurrence for an existing resource to be displaced. Id., p. 16.

2. Comments

The Siting Council received a wide range of comments regarding the treatment of committed resources.[16] The five electric companies that commented on the subject of committed resources urge that existing generation, existing purchases, and pre-approved C&LM programs be considered committed. BECo states that it prefers that all of these resources be deemed committed automatically, in part due to the complexity of the IRM process and its tight time schedule (BECo Comments, pp. 9-10, BECo Final Comments, p. 4). WMECo, MECo and NEPCo argue that the goals of IRM should not include the evaluation of existing resources, or those resources that have approved contracts (WMECo Comments, pp. 14-15; MECo/NEPCo Comments, p. 1, MECo/NEPCo Final Comments, pp. 5-12). MECo and NEPCo warn that repeated ranking of resources "would add uncertainty . . . that would increase risks to project developers and costs to utility customers" (MECo/NEPCo Comments, p. 1). MECo and NEPCo also suggest that the IRM proceeding would be delayed by litigation over existing

16/ Certain of these comments were received prior to the issuance of the Department's Order of August 31, 1990 (and were available to the Department for consideration prior to the issuance of its Order). Comments cited as "Final Comments" herein were received after August 31, 1990.

resources (id.). CECo, CELCo, EECo, and Montaup argue that the difficulties and costs resulting from the removal of existing resources from the committed resource classification are not justified by the possible benefits (CECo/CELCo Final Comments, pp. 1-2; EECo/Montaup Final Comments, pp. 16-17).

The New England Cogeneration Association ("NECA") emphasizes that the review of existing plants and purchases would have a disruptive effect on the development of power projects in the Commonwealth (NECA Comments, pp. 2-4). NECA suggests that existing plants and projects that already have secured financing have done so without knowledge of the possibility of being subjected to competition (id., p. 2). Therefore, continues NECA, if there is any possibility that a resource can be rendered uncommitted, extensive litigation can be expected over such a decision (id.).

NECA maintains that the possibility of challenges to signed and approved power sales contracts will chill the independent power market (NECA Final Comments, pp. 3-6). In addition, NECA suggests that the provision of a safe period for contracted resources, one which would exempt them from committed resource review, could add stability to the process (Tr. 2, pp. 30-31). Several NECA members indicated that a 15-year safe period is necessary to protect projects (id., pp. 6, 31, 52-53).

NECA acknowledges the contractual assurances concerning power purchase agreements made by the Department in D.P.U. 89-239, but explains that a variety of obstacles would remain (id., p. 34; NECA Final Comments, p. 6). In particular, NECA notes that the development of cogeneration facilities requires long-term contracts with industrial steam hosts, contracts which simply would not be executed if steam hosts believed there was any possibility that the cogenerator could cease to operate during the term of the contract (NECA Final Comments, p. 6).

Several parties took the position that no resources should be protected from competition. CLF and SESCO assert that resource plans should be optimized without protecting any resources from comparison with alternatives (CLF Final Comments, p. 3; SESCO Final Comments, pp. 17-18). DOER suggests that no planning benefits arise from designating any resources as committed (DOER Comments, p. 5). Citizens Conservation Corporation ("CCC") also suggests that existing and planned resources should be compared to other resources (CCC Comments, p. 1).

Boston Gas Company ("BGC") points to the Department's assurances to resource developers in D.P.U. 89-239, and argues that these assurances are sufficient to ensure contractual terms and satisfy developers' financing obligations and profits (BGC Final Comments, pp. 2-3). MASSPIRG concurs with BGC's position (MASSPIRG Comments, pp. 1-2).

MASSPIRG also takes issue with the Siting Council's proposal to review comprehensively only those existing resources that have failed to perform. MASSPIRG states that [t]he main problem with the Siting Council's proposed "extraordinary circumstances" standard of review . . . is that it would increase administrative complexity rather than decrease it (MASSPIRG Comments, p. 3). According to MASSPIRG, it would require an additional level of review, and lead to pointless debate and litigation over the definition of "extraordinary" and its application in the particular circumstances (id.). In addition, MASSPIRG suggests that an existing plant can be compared with other resources only after it has operated for a number of years (Tr. 2, pp. 148-149). Therefore, MASSPIRG indicates that the protection of planned resources in the IRM process may be necessary for pragmatic reasons (MASSPIRG Final Comments, pp. 1-2).

3. Analysis and Findings

No single issue in the Siting Council's IRM rulemaking has generated as much controversy as the issue of whether planned and existing resources should be subjected to competition in the all-resource solicitation. Numerous electric companies and third-party developers expressed grave concern regarding any proposal that would require planned resources with signed and approved contracts or operating resources to compete in the all-resource solicitation.

The first alternative approach as proposed in EFSC 90-RM-100, in which all of an electric company's existing and planned resources are subject to competition, is attractive in theory.[17] First, by subjecting both existing and proposed resources to the same competitive process, the Siting Council and Department would be able to ensure that a utility's entire supply portfolio -- and not just its newly acquired resource set -- is truly reliable and least-cost. Through the application of environmental externality values to all resources, the region's older plants -- plants which tend to cost less to run but tend to have higher externality "costs" -- could be replaced systematically by cleaner resources, and the state's entire generation mix could be optimized over time.

The Siting Council and the Department have stated that a workable regulatory system which leaves open the possibility of viewing planned or existing resources as uncommitted could be achieved without dislocating the market for utility and third-party generation. The Department has emphasized that both utilities and third-party developers would be entitled to full recovery for any replaced resource, either under a traditional cost-of-service framework or by guaranteeing any revenue stream to which a third-party developer is entitled under the specific terms of its power sales contract. In addition, the two agencies have expressed the opinion that it would be rare for an existing resource to be displaced through bidding because variable cost and many non-price factors almost always favor existing units. See, e.g., D.P.U 89-239, p. 16.

Notwithstanding the theoretical attractiveness of an approach which would subject each of an electric company's planned and existing resources to competition, in light of the

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17/ The second proposed alternative is similar to the first proposed alternative in that many existing units would be subject to competition. Our comments concerning the first proposed alternative also apply, in large measure, to the second proposed alternative.

comments received, the Siting Council deems it most appropriate at this time to adopt the standard for planned and existing resources set forth initially in our July 5, 1990 Order. Under this standard, (1) planned resources will not be subject to competition from new energy resources, and (2) existing units will not be subject to competition from new energy resources (except in the case where an electric company requests and shows that a resource owned by the electric company or affiliate should be subject to competition, or in the case where extraordinary circumstances are present). Thus, our review under IRM is consistent with our standard in the 1989 BECo Decision. There, the Siting Council held that, absent extraordinary circumstances, a planning process which required an ongoing analysis of existing generation would increase unnecessarily the difficulty of developing and reviewing a supply plan (18 DOMSC at 254). However, the Siting Council also held in that case that:

> [C]companies should evaluate existing generating units within a supply planning process when extraordinary circumstances result in questions about the reliability or economic advantages of those units when compared to other resource options. We expect such extraordinary circumstances to occur rarely. Id., at 254-255.

We reach the decision to accept all planned and existing resources as part of an electric company's resource inventory, with the exceptions noted above, for the following reasons.

First, despite the attractiveness of a process that would require an electric company to select the optimal mix from existing, planned, and proposed resources, we are concerned that the real effect of such a plan at present might be to introduce significant uncertainty into the energy resources market.

We are persuaded by NECA's comments that a system that raises the possibility that a planned or existing resource may be displaced makes new projects more difficult and costly to finance. In addition, the steam hosts, which, of course, are essential to a cogeneration facility, may well object to a development proposal if they could be left without their steam provider without warning.[18] So, the practical result of an attractive theoretical plan may be to discourage unnecessarily the competitive generation market, including true cogeneration projects, which the Comnonwealth has endeavored to foster over the last several years.

A further practical consideration is the fact that the New England Power Pool ("NEPOOL") now dispatches generating units solely on a variable production cost basis that does not factor in environmental externalities. This could create a serious conflict between the resource mix that results from the IRM process and the manner in which units actually are dispatched.

Second, IRM is a new regulatory framework which represents a significant departure from the existing system of regulation and resource procurement. The Siting Council and Department expect IRM, as a new regulatory framework, to experience its fair share of "growing pains." A review by the Siting Council of an electric company's resource inventory to determine which resources are committed, or a review by the Department of an award group selected from a competition among all existing, planned, and bid resources, would raise enormous administrative difficulties. These difficulties ultimately could serve to undermine the entire IRM framework.

Also, any determination regarding the competitive ranking of a planned or existing resource rests to a large extent on the cost implications of monetizing environmental externalities. However, the monetized values of environmental externalities set forth by the Department in D.P.U. 89-239 (the values in place at present) are acknowledged to be

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18/ We recognize that most existing QF contracts do not contemplate the possibility of displacement and, therefore, would not be subject to displacement in any event. Our concern about the immediate effect of considering whether existing resources are uncommitted involves the market for new contracts.

preliminary. See D.P.U. 89-239, p. 76. With values that are subject to change, and with no experience implementing IRM, a bidding scheme that includes older generating units is not advisable.

Third, we recognize that one of the primary goals of our theoretical model -- the systematic replacement of older, less efficient, dirtier resources with cleaner options -- continues to be addressed in other arenas. The recent enactment of federal clean air laws is indicative of other efforts on the state and federal level aimed at limiting externalities caused by the existing power-plant stock in a cost-effective fashion.

Fourth, while we acknowledge the arguments of those who contend that an "extraordinary circumstances" standard is difficult to apply, we disagree that there is any insuperable obstacle to developing and following this standard. This is especially the case because we expect a unit will fall under the "extraordinary circumstances" standard in only the most rare of instances, and this standard is not intended as a vehicle for continuing arguments that existing power plants be subjected to competition.

Finally, it is essential that we not forget the purpose of the IRM rulemaking as well as the Siting Council's mandate. In establishing an IRM framework, the Siting Council and Department have endeavored to devise an improved method for utilities to acquire new resources to meet their obligation to serve customers reliably in a least-cost, least-environmental-impact manner. This emphasis on the acquisition of new resources is consistent with the Siting Council's statutory mandate as well as its case law.

Accordingly, the Siting Council finds that no planned or existing resources will be subject to competition from new energy resources, except for (1) those units owned by host electric company or an affiliate which the electric company itself shows should be excluded from its resource inventory, and (2) those units, which after review under the extraordinary circumstances standard, are excluded by the Siting Council from the electric company's resource inventory.[19]

We wish to emphasize, however, that the Siting Council remains committed to reviewing the electric company's resource inventory[20] and, based on this review, making adjustments to the resource need, if warranted. This would be accomplished in three possible ways. First, an electric company is required to present its assumptions and methodology for predicting attrition of planned resources. If an electric company cannot establish that its assumptions and methodology for predicting attrition of planned resources are appropriate, the Siting Council may make an adjustment to the host utility's resource need. See Section II.E, below.

Second, the Siting Council will review how an electric company's existing resources have operated (e.g., capacity factor for a base load unit) in order to determine whether each unit's performance has been incorporated appropriately into the utility's estimate of resource need. If the actual performance of the company's existing resources is not reflected appropriately in the utility's estimate of resource need, the Siting Council may adjust the resource need.

Third, as discussed above, in the rare cases of "extraordinary circumstances," the Siting Council will review an existing resource's performance to determine whether that resource should be removed from an electric company's resource inventory and subjected to competition in Phase II of IRM.

19/ In light of our decision to accept all existing and planned resources as part of an electric company's resource inventory -- and not subject these resources to competition in Phase II of IRM -- it is no longer necessary to distinguish between "committed" resources and "uncommitted" resources. Therefore, our regulations do not employ these terms.

20/ While the Siting Council will not be reviewing the cost, performance and environmental aspects of existing resources for determination of committed status, the regulations require that the electric company provide information on these aspects in the initial filing. 980 CMR 12.03(7)(b)(2) and (3). This information will be used by the Department in their Phase III evaluation of the company's optimization of the award group.

E. Attrition

1. Background

In its proposed regulations, the Siting Council required each electric company to apply an attrition factor "to its planned resources to account for the contingency that planned resources may not meet the electric company's expected performance levels for such resources." 980 CMR 12.03(7)(a). In its Order, the Siting Council further stated that the adjustment for attrition is not intended to change the inventory of planned resources but only the size of the resource need.[21] EFSC 90-RM-100, p. 27.

2. Comments

All commenters on this issue agreed that the use of an attrition factor is appropriate to aid in determining resource need. MECo, NEPCo and BECo recommend that an attrition factor should be used for particular planned resources, but further stated that only an overall attrition factor should be made public (MECo/NEPCo Final Comments, p. 25; Tr. 1, p. 169). MECo and NEPCo explain that it may be necessary for a utility to treat as confidential the information it has regarding its assessment of a specific project to protect the interests of the utility and the project developer (MECo/NEPCo Final Comments, p. 25). EECo and Montaup support the use of an attrition factor and state that measurable milestones in a project's development should be used to ascertain this factor (EECo/Montaup Final Comments, p. 18). BECo and WMECo suggest that the uncertainty or attrition of planned resources can be addressed through sensitivity analyses (BECo Final Comments, pp. 10-11; WMECo Final Comments, p. 3).

21/ In EFSC 90-RM-100, the Siting Council discussed attrition in the context of committed resources (pp. 26-28). In this Order, these two issues are discussed separately (see Section II.D, above). The application of attrition factors to planned resources will contribute to the determination of the electric company's resource need.

WMECo also advocates developing milestone-by-milestone attrition factors from the actual experience of projects that have been developed previously (WMECo Comments, p. 22). WMECo states that it would apply these factors to each planned resource as the development of that resource progressed (id.).

SESCO agrees that the use of an attrition rate is appropriate and states that each electric company should develop its own attrition rates, with the proviso that the attrition rates must be developed in such a way that they are reviewable (SESCO Comments, p. 18). NECA did not comment on the use of attrition factors for determining resource need, but did recommend that milestones not be used to review the inclusion of specific plants in supply plans (NECA Comments, p. 2). NECA warns that such focus on a specific plant could lead to "extensive litigation regarding the appropriate status of a plant, [and] the continued viability of planned projects regardless of contractual milestones...." Id.

3. Analysis and Findings

In the proposed regulations, the Siting Council required electric companies to use an attrition factor for planned resources in order to ensure that the size of an electric company's resource solicitation is adequate. No commenter took issue with the need to apply some attrition factor or factors to take into account the near certainty that not all of an electric company's planned resources will be developed and come on line as expected. Accordingly, the Siting Council finds that electric companies shall adjust their resource inventory to take into account the attrition of planned resources. However, at this time the Siting Council will not mandate any method for predicting the attrition of planned resources. The Siting Council recognizes that the appropriate methodology for predicting the attrition of planned resources may vary from electric company to electric company, and from one IRM filing to another for a single electric company.

In mandating the use of attrition factors, the Siting Council is sensitive to concerns regarding public disclosure of an electric company's assessment of the likelihood that a particular resource will meet its contract milestones and commence operation on schedule. Nonetheless, it is essential that an electric company provide the Siting Council with sufficient information and documentation to support its selection and application of an attrition methodology. We are confident that, on a case-by-case basis, we can protect our interest of determining an electric company's resource need through a fully documented decision while protecting the legitimate confidentiality interests of electric companies and third-party resource developers.

F. Resource Need

1. Characteristics of Resource Need

a. Background

Under present Siting Council review, each electric company is required to develop and apply appropriate criteria for screening its array of available resource options. See 1989 NEES Decision, 18 DOMSC at 337-338; 1989 BECo Decision, 18 DOMSC at 25-226; 1988 EUA Decision, 18 DOMSC at 102-103. Under the proposed IRM framework, the electric company's screening criteria for new resources are based on the electric company's estimate of resource need. The Siting Council's findings on resource need will be used by the Department to review the electric company's criteria in the RFP scoring system. See 220 CMR 10.03(6). Further, when the electric company selects the award group of the resource proposals for Department approval in Phase III, the selections will have been based on the electric company's identification of resource need.

Under the proposed regulations, the electric company is required to identify the resource need by (1) summarizing the resource need by kilowatts of summer and winter capacity, and kilowatthours of total annual energy requirements, and (2) describing the general characteristics of resource need including: base-load, intermediate-load, or peaking-load needs; equivalent availability needs; in-service date; on-peak, off-peak and seasonal production requirements; fuel diversity preferences; technology diversity preferences; voltage control needs; and locational needs. 980 CMR 12.03(8). In its Order in EFSC 90-RM-100, pp. 31-32, the Siting Council requested comments on the review of the electric company's evaluation of resource need.

b. Comments

BECo maintains that electric companies should not be required to provide general characteristics of resource need (BECo Comments, pp. 13-14; BECo Final Comments, pp. 1-2). BECo contends that providing the general characteristics of resource need in the initial filing could lead to the sending of an incorrect message as to the type of facility that could win the solicitation, and may discourage developers from offering other resources (BECo Comments, p. 14, BECo Final Comments, p. 2; Tr. 1, pp. 162-164). BECo asserts that, as a result, developers are more likely to choose the same technology as the electric company, and attempt to beat the price (BECo Final Comments, p. 2). Finally, BECo maintains that the most appropriate place in the IRM process to make a specification of the characteristics of resource need is in the RFP criteria (BECo Comments, p. 2).

Contrary to BECo's position, MECo and NEPCo assert that the general information required under the proposed regulations will aid bidders and improve the quality of the proposals received (MECo/NEPCo Final Comments, p. 27).

c. Analysis and Findings

The Siting Council agrees with MECo and NEPCo that providing the general characteristics of resource need should assist project developers with their bids and improve the quality of the bid proposals received by the electric companies. With this information, project developers would be provided with some insight as to the general needs of the host electric company. In addition, these general characteristics are available to the host electric company in developing its initial resource portfolio, and should be revealed so as to assist other project developers in their effort to provide resources.

We do not share BECo's concern that divulging this information at this stage would inhibit the development and acquisition of resource proposals. These characteristics of need are guidelines and not requirements for additional resources. Further, the electric company's RFP, which is included in the initial filing and reviewed by the Department in Phase I, will reflect these characteristics.

In sum, project developers should be guided by the greatest amount of information possible concerning the electric company's identification of resource need. The Siting Council finds that to deny such information to all project developers is not in the public interest. Accordingly, the resource need filing requirements proposed in EFSC 90-RM-100 are not changed in these final regulations.

2. Diversity

a. Background

In the course of technical sessions and hearings in this docket, the Siting Council requested that parties comment on whether the Siting Council should make findings in Phase I regarding utility diversity. Specifically, commenters were asked to address a regulatory scheme under which an electric company would be required to submit information in its initial filing regarding (a) the diversity of its existing supply plan; and (b) the diversity targets it plans to meet as a result of the IRM cycle. Under this proposal the Siting Council would make findings regarding the diversity of the electric company's current supply plan and the appropriateness of its diversity targets, and the Department, in turn, would accept the Siting Council's diversity findings for the purpose of reviewing the electric company's RFP criteria and criteria weights in Phase I.

b. Comments

While all commenters acknowledged the importance of diversity[22] in a utility's resource planning, the commenters were divided on the question of whether diversity findings by the Siting Council in Phase I would be helpful to the overall IRM process. CLF and MASSPIRG generally support utilities providing as much information as possible regarding fuel diversity (MASSPIRG Final Comments, p. 2; CLF Final Comments, pp. 3-4). DOER strongly supports the concept of diversity findings by the Siting Council in Phase I, noting that such findings would benefit the Department in its Phase I review of RFP criteria and its Phase III review of actual resource selection (DOER Final Comments, pp. 1-4). In addition, Energy Research Group, Inc. ("ERG") asserts that the regulations should accommodate different supply sources, such as base, intermediate, and peaking technologies (ERG Final Comments, p. 1).

BECo argues that electric companies should be given the option of establishing diversity targets and including them in RFPs submitted in Phase I (BECo Final Comments, p. 5). BECo further notes that when electric companies avail themselves of this option, the Siting Council and Department would review these targets as part of the IRM process (id.). WMECo similarly comments that an electric company could develop diversity objectives and incorporate these objectives in its RFP criteria and weightings (WMECo Final Comments, p. 4). However, WMECo

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22/ While a number of commenters addressed the diversity issue in terms of fuel diversity alone, the Siting Council notes that there are many dimensions to the diversity of a utility's resource plan. In addition to fuel diversity, diversity encompasses the different plant sizes and technologies represented in an electric company's resource plan; whether the utility's plants are base-load, intermediate, or peaking; the utility's reliance on purchased resources relative to company-owned resources; whether the utility's demand-side resources are conservation resources, load-management resources, or fuel-switching resources; and the capacity and energy provided by demand-side resources resources versus that provided by supply-side resources.

asserts that an electric company also can meet its diversity objectives through the optimization process in Phase III of the IRM cycle (id., pp. 4-5).

MECo and NEPCo argue that the Siting Council should not impose a Phase I filing requirement regarding diversity objectives (MECo/NEPCo Final Comments, p. 28). MECo and NEPCo further comment that review of an electric company's diversity objectives should await evaluation of the utility's final award group (id.). MECo and NEPCo also appear to argue that diversity criteria should not be included in an electric company's RFP because inclusion of such criteria may require the utility to pay for a non-price factor that the marketplace otherwise might provide at little or no cost (id.).

EECo and Montaup offer comments opposing the review of diversity objectives in Phase I, arguing that diversity guidelines cannot be established without also considering a resource's cost, reliability and environmental characteristics (EECo/Montaup Final Comments, p. 15).

Eastern Energy comments that "some affirmative action" by the Siting Council on the issue of diversity is necessary to counteract the effect of the Department's regulations monetizing environmental externalities (Eastern Energy Final Comments, p. 1).[23] Eastern Energy argues that the Department's rules for monetizing environmental externalities place coal-fired generation projects at a distinct disadvantage in the IRM process (id., p. 2). While Eastern Energy supports the monetization of non-price factors such as reliability, security, and diversity, it recognizes that such monetization may be extremely difficult to accomplish (id., p. 3). Therefore, Eastern Energy argues that the Siting Council is in the best position to provide guidance to the Department on the appropriate weights for diversity criteria (id.).

23/ The Department rules on the monetization of environmental externalities are set forth in D.P.U. 89-239, pp. 51-85 and at 220 CMR 10.03(6)(d)(3)(f).

Finally, NECA comments that while diversity is an important consideration in resource planning, more research and discussion are needed before addressing this question in final rules (NECA Final Comments, p. 19).

c. Analysis and Findings

The Siting Council finds that a Phase I review of an electric company's diversity objectives will serve to improve the IRM process. We also find that it is appropriate for the Siting Council to conduct such a Phase I diversity review. In our current reviews of electric company supply plans, the Siting Council has noted that a review of diversity is consistent with its mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, sec. 69H; 1989 NEES Decision, 18 DOMSC at 336; 1989 BECo Decision, 18 DOMSC at 224; 1988 EUA Decision, 18 DOMSC at 100; Middleborough Gas and Electric Department, 17 DOMSC 197, 205 (1988); 1988 NU Decision, 17 DOMSC at 19.

Historically, while regulators, utilities, project developers, and public interest groups have recognized that diversity is an important element in resource planning, these groups have not agreed on a particular method for ensuring that diversity is consistently and appropriately considered in resource planning decisions. The IRM process must include specific regulatory methods that ensure that diversity objectives in the public interest can be achieved.

Since the all-resource solicitation stands as the cornerstone of the IRM process, the RFP issued by an electric company in Phase II must send accurate signals to resource providers regarding an electric company's diversity objectives. By making Phase I findings on the appropriateness of a utility's diversity objectives, the Siting Council can help the Department ensure that the correct diversity criteria and weights are incorporated in the electric company's RFP.

We disagree with commenters who argue that the inclusion of diversity criteria in an electric company's RFP somehow would require electric companies to consider diversity separately and without the benefit of other important criteria such as cost and reliability. A utility's diversity objectives certainly cannot be considered in isolation, and inclusion of diversity criteria in RFPs should not encourage such a result. On the contrary, inclusion of diversity criteria in utility RFPs will allow electric companies to consider diversity objectives explicitly along with other price and non-price criteria.

The Siting Council also finds that Phase I findings on the appropriateness of a utility's diversity objectives will assist the Department in its review of an electric company's optimization and negotiation processes in Phase III. Since the Siting Council and the Department acknowledge that diversity will be an essential factor in decisions made by electric companies in Phase III, an explicit statement of the utility's diversity objectives only can help to improve the optimization and negotiation processes as well as the evaluation of those processes.

Finally, we reject the notion that the Siting Council must take "affirmative action" on the diversity question as a means of counteracting problems perceived as arising from the Department's decision to monetize environmental externalities. First, the value of environmental externalities and the value of diversity are independent. The need for fuel diversity does not diminish or eliminate the damage caused by a particular emission. Diversity must be evaluated because, in and of itself, it represents a social value and not because it must be used to counteract externality values. Second, the Siting Council notes that the monetary values of environmental externalities are not "set in stone," since the Department has stated that electric companies and interested parties will have the opportunity to address these monetary values on a case-by-case basis. D.P.U. 89-239, p. 76. Third, the Department has ruled that the relationship between the combined price/environmental externality category and other non-price criteria may vary across electric companies. Id., p. 74. In fact, the Department explicitly recognizes that an electric company which is highly dependent upon oil may place a different weight on its combined price/environmental externality criterion than an electric company which generates its electricity from a diverse set of fuels. Id.

Therefore, the Siting Council does not agree with Eastern Energy that the Department's monetization of environmental externalities creates an insurmountable bias against coal which must be remedied by the Siting Council. Instead, the Department's approach to evaluating environmental externalities is part of a larger weighting scheme designed to recognize the value of various attributes of resource options. Under such an approach, an electric company's diversity objectives may favor a fuel option not present in a company's resource mix, especially fuel options such as coal whose price may be unrelated to volatile oil markets. In this manner, an electric company's diversity objectives conceivably could have a countervailing effect on that company's weighting of environmental externalities. This approach only underscores the importance of clear diversity findings by the Siting Council in Phase I.

In sum, the Siting Council will require an electric company to include in its resource inventory, a summary of capacity and energy resources by: fuel type; plant size and technology; plant type (i.e., base load, intermediate or peaking); ownership; demand-side resource type; and reliance on supply-side resources relative to demand-side resources. In addition, as part of its identification of resource need, the Siting Council also will require an electric company to present its diversity objectives for each of the aforementioned categories. The Siting Council will review and make Phase I findings relative to diversity regarding both the resource inventory and the identification of resource need and report these findings to the Department for use in its Phase I review of the electric company's RFP and its Phase III review of the electric company's optimization and negotiation processes.

G. Resource Technical Potentials

Under the proposed regulations at 980 CMR 12.03(9), the EFSC required electric companies to identify the technical potential of certain resource options. In particular, under the proposed regulations, electric companies are required to identify the technical potential of C&LM in their service territories, and the technical potential for life extension and repowering at existing plants.

1. C&LM

a. Background

The electric companies have considerable knowledge concerning the end-uses of electricity in their service territories. The electric companies also possess the best information on the extent of efficiency improvements which have been achieved for each end-use through existing C&LM programs. However, untapped efficiency potential may remain in these end-uses which could be pursued by developers of C&LM resources, including the electric company. To encourage full consideration of the technical potential of C&LM, the electric companies are required under the proposed regulations at 980 CMR 12.03(9)(a) to provide detailed data and information on this technical potential.[24] In its Order, the Siting Council requested comments on requiring electric companies to identify the technical potential of C&LM, and asked commenters (1) whether end-use ownership surveys should be required to estimate the technical potential of C&LM, and (2) whether methodologies to estimate the technical potential of C&LM should be consistent across all utilities. EFSC 90-RM-100, p. 34. In addition, during the hearings, the Siting Council asked commenters whether

24/ The requirement for identifying the technical potential of C&LM originated with the Department's effort to require companies to design optimal C&LM programs. See D.P.U. 86-36-F, p. 26 (1988).

fuel switching should be included as a component of the technical potential of C&LM (Tr. 2, p. 206).[25]

b. Discussion

Generally, the commenters supported requiring electric companies to identify the technical potential of C&LM. For example, MECo and NEPCo state that the technical potential of C&LM appropriately can be provided in the initial filing (MECo/NEPCo Final Comments, p. 27). BECo states that it already provides estimates of the technical potential of C&LM in its annual filings with the Department (BECo Comments, p. 15). However, most commenters did not support the imposition of specific methodological approaches to estimate the technical potential of C&LM. BECo argues that the regulations should not require a specific methodology but should allow electric companies the flexibility to adopt new methods for estimating C&LM potential as these methods are developed (id.). WMECo asserts that the assessment of C&LM technical potential cannot be totally consistent across all utilities because of differences in data, modeling capabilities, and resources, although WMECo did state that electric companies would benefit from standardized assumptions concerning the effectiveness of efficiency improvements (WMECo Comments, p. 25). CLF encourages tolerance of estimation methods which can be improved in subsequent filings (CLF Comments, pp. 1-2). However, MASSPIRG advocates a consistent methodology across all utilities and calls for the electric companies to employ end-use ownership surveys (MASSPIRG Comments, p. 4).

Most of the comments concerning methodologies for estimating C&LM technical potential emphasize flexibility. The Siting Council is persuaded by these arguments. As a result, the final regulations will not include a specific method for

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25/ The potential inclusion of fuel switching as a C&LM option was raised by the Department in D.P.U. 89-239, p. 25. See Section II.G.2., below, for a discussion of fuel switching technical potential.

estimating the technical potential of C&LM. However, the Siting Council notes that the technical potential of conservation will differ from the technical potential of load management and, therefore, there will be different methods for estimating such technical potentials. Therefore, the final regulations require electric companies to report conservation technical potential separately from their reporting of the technical potential of load management.

2. Fuel Switching

a. Comments

In its initial comments, BGC urges the Siting Council to address, in the instant proceeding, the treatment of fuel-substitution measures within the context of electric companies' least-cost resource planning and to require that fuel substitution measures be evaluated on an equal footing with other electric demand-side options (BGC Comments, pp. 1, 5). BGC states that "fuel-substitution measures represent a significant resource that will not be identified, let alone evaluated, by electric utilities unless they are required to do so" (id., p. 5). In support of this contention, BGC cited letters from two electric utilities indicating "that [the electric companies] do not invest in conservation measures involving fuel-substitution" (id.).

Subsequently, during the Siting Council's public hearings on its proposed IRM rules, we requested comments from all parties regarding the inclusion of fuel switching potential in electric company estimates of the C&LM technical potential in their respective service territories (Tr. 2, p. 206).

In its final comments, BGC reiterates its request that the Siting Council in its final regulations recognize fuel substitution as a "bona-fide load management measure" for electric companies "meriting evaluation and investment to the same extent as other C&LM" (BGC Final Comments, p. 13). Specifically, BGC states that "within the Phase I framework, electric utilities must be required to include estimates of technical potential for fuel-substitution in the same fashion as

C&LM technical potential" (id., p. 11). BGC asserts that "electric-to-gas fuel substitution programs, as a class, represent an economical and environmentally superior resource that electric utilities are persistently ignoring" (id., pp. 5-6). BGC further states that, in D.P.U. 89-239, the Department required electric companies to evaluate fuel switching programs in the IRM process (id., p. 6). Consequently, BGC asserts, for the joint IRM regulatory review process to be successful, "the Siting Council can and should assure that electric utilities seek out and evaluate fuel substitution programs in the same manner as they solicit other resource opportunities" (id.).

With regard to the argument that competition among alternate energy supplies should be left to market forces, BGC states that "there are a number of market barriers which prevent consumers from making efficient energy choices based on life-cycle costs," and that these same economic barriers exist to prevent cost-effective fuel substitution measures (id., p. 7). BGC also states that "fuel-substitution programs . . . are invariably preferable from an environmental perspective," citing calculations comparing the environmental externality costs of gas versus the environmental externality costs of electric heating and cooling (id., p. 10).

CLF, DOER, and CCC each generally favor the inclusion of fuel switching in electric utilities' estimates of C&LM technical potential (CLF Final Comments, p. 2; Tr. 1, 46-53, 99-102; CCC Final Comments, pp. 5-6). CLF states that it "supports the inclusion of socially cost-effective fuel switching that could be achieved through electric utility DSM [demand-side management] programs in electric company estimates of C&LM potential," but that it is concerned about substantial existing data gaps, such as the lack of information among electric companies regarding the availability of gas service, which could prevent a precise quantification of this potential (CLF Final Comments, p. 2). CLF recommends examining the issue of developing technical potential estimates for fuel-switching programs on a case-by-case basis (id.).

CCC states that "fuel switching should be explicitly defined as electric energy conservation, and should be part of the EFSC's required estimate of technical potential" (CCC Final Comments, p. 5). CCC further asserts that "in terms of its lost sales impact, the effect of fuel switching is really no different than the effect of any other conservation improvement" (id.). According to CCC, "if the rules work well, the utility will be fully compensated . . . for the lost profit on the lost sale" and "the utility benefits by getting a return that is directly proportional to any and all payments they make toward the conversions." (Tr. 1, pp. 101-102).

In general, however, the electric companies are opposed to the consideration of fuel switching as a form of C&LM and thus the inclusion of fuel switching potential in electric company estimates of C&LM technical potential. BECo states the benefits of expanding the technical potential of C&LM to include fuel switching are unclear and suggests that it would be more appropriate for the Department to consider this issue in a proceeding focusing on C&LM programs (BECo Final Comments, pp. 5-6). BECo contends that the marketplace works properly with respect to inter-fuel competition (id., p. 6). BECo further states that "there has been no support for Boston Gas' contention that there is a substantial potential for fuel substitution" and that "without a demonstration of the efficacy of including fuel substitution in the regulations, it is not appropriate to include such a requirement" (id.).

CECo and CELCo state that BGC's suggestion that electric utilities be required to list the technical potential for converting electric end-uses to natural gas is problematic because an electric company does not generally possess information on the availability of natural gas for any particular customer (CECo/CELCo Final Comments, p. 4). CECO and CELCo assert that "it may be reasonable for gas utilities to pay some, if not all, of the costs of converting end-uses to natural gas where societally cost-effective" (id.).

CECo and CELCo also state that there is a need to review alternate fuels besides natural gas in assessing fuel switching opportunities to determine which fuel may be preferred in a given end-use conversion (id., pp. 4-5). CECo and CELCo argue that the "subsidization of competitive fuels could work to the long term detriment of ratepayers" and suggests that "the EFSC's IRM regulations could allow, but not mandate, fuel-switching as a potential resource available to electric utilities" (id., p. 5).

MECo and NEPCo state that at least three discrete issues must be considered in evaluating whether electric companies should subsidize fuel switching: (1) "whether the use of gas, oil, or electricity presents any significant social benefit to society;" (2) whether, if we conclude that one fuel source is clearly preferable to another, payments or incentives are required to correct any market imperfections; and (3) if market intervention is warranted, which energy supplier should make the payment to support the conversion (MECo/NEPCo Final Comments, p. 23).

MECo and NEPCo assert that "the key finding of a market imperfection that was necessary to support utility intervention in conservation must also be made on fuel switching" (id.). MECo and NEPCo further state that "as a general principle, the cost of conversion should be paid for by the party that benefits from it" and thus that, "if market intervention is appropriate, gas utilities should pay for conversions to gas and electric customers should pay for conversions to electricity" (id., p. 24). MECo and NEPCo conclude that the three issues that it has raised require "a full evaluation in light of the facts and circumstances facing the utility at any given point in time" and the Siting Council and DPU "should not establish any firm rule on the fuel switching issue, but should investigate it in the continuing IRM proceedings on specific company filings" (id.).

WMECo states that there are a number of reasons why equating fuel switching with energy efficiency is not in the utilities' or society's best interests (WMECo Final Comments, p. 7). First, WMECo asserts that gas utility shareholders would profit from fuel switching at the expense of electric ratepayers and that "electric ratepayers would be further harmed because electric rates would need to rise to cover the electric utilities' fixed costs, which in turn would expose the utilities to additional losses in response to price increases" (id., pp. 8-9). Second, WMECo states that electric company financial support for fuel switching would harm electric utilities' competitive position, whereas utility investments in end-use efficiency improve the competitiveness of electricity as a fuel choice (id., pp. 10-12). WMECo states that "fuel switching should be the logical choice of last resort, i.e., only after all alternatives for providing greater value have been explored" (id., p. 12). Third, WMECo states that fuel switching may not be a least-cost alternative for electric utilities, that "it could well be detrimental to natural gas customers from a rate perspective" and that "fuel switching does not necessarily, and, possibly never, leads to least-cost plans for either electric or gas utilities" (id., pp. 14-16). Finally, WMECo asserts that the promotion of fuel switching would have adverse environmental consequences since it "could further delay the need to install new generating facilities and thus prolong the use of older, dirtier facilities" and added that "gas-fired alternatives have their own environmental consequences" (id., pp. 16-18).

WMECo concludes that "there may well be some circumstances where fuel switching would be in the long term interests of both electric and gas utilities," but that under such circumstances "the gas utility should be able to demonstrate that its customers benefit from the switch and therefore, should fund the subsidy. It does not represent a situation in which electric ratepayers should be required to bear the cost of subsidizing the switch to an alternative fuel" (id., pp. 18-20).

b. Analysis and Findings

The Siting Council agrees with BGC that electric companies, in designing their least-cost, least-environmental-impact resource plans, must evaluate all resource options, including fuel switching, on an equal footing. The Siting Council also agrees with CCC that in many respects fuel switching is the functional equivalent of traditional conservation; however, we recognize that significant differences exist as well. Therefore, the Siting Council finds here that it is appropriate for electric companies to include the technical potential of fuel switching in their estimates of demand-side technical potential. In the final regulations we require that the electric company's estimate of technical potential of fuel switching be developed and reported separately from the technical potential of conservation and the technical potential of load management.

In making this finding, the Siting Council in no way is making a judgment regarding the economic or environmental attractiveness or viability of fuel switching as a resource option for electric companies nor the rate treatment of fuel switching by either electric or gas companies. We are simply stating that it is not appropriate for electric companies to eliminate fuel switching from their portfolio of potential resource options <u>a priori</u>. The costs and benefits of fuel switching proposals may vary considerably. Each must be evaluated in the context of an electric company's IRM process together with the company's other supply- and demand-side options. In this manner, only fuel switching proposals which are superior to other options, and thus by definition are least-cost, will be selected. Electric company ratepayers and society would benefit because any program selected under the IRM process will be least-cost.

The data provided to the Siting Council in Phase I of the IRM process must be fully consistent with that required by the Department in the later evaluation phases of the IRM cycle. In D.P.U. 89-239, the Department states that its final IRM regulations require that electric companies "must accept and evaluate C&LM proposals from third-party C&LM developers" and that "such proposals may include proposals for fuel-switching that electric companies would have to evaluate in Phase II according to Department-approved resource evaluation criteria and cost-effective[ness] methodology" (pp. 24-25). The Siting Council's finding above therefore is consistent with the Department's stated intention to allow fuel switching proposals to be considered in Phase II of the IRM process. The Department will determine who pays for any approved fuel-switching program on a case-by-case basis.

Several commenters have noted the potential difficulties of estimating the technical potential of fuel switching due to a lack of knowledge among electric companies regarding the availability of pipeline gas. However, we have made no suggestion that fuel switching is limited to electric-to-gas conversions. Oil, propane and other fuels/technologies may also represent potential substitutes for electricity in certain end-uses. Thus, it will not be necessary for electric companies to gather detailed data on the local availability of pipeline gas in estimating the technical potential for fuel switching. Rather, estimates of the technical potential for fuel switching should focus on analyses of electric end uses for which commercially available technologies exist that utilize alternative fuels. This is consistent with the estimation of the technical potential for C&LM.

In sum, the final regulations require the electric company's estimate of the technical potential of fuel switching be developed and reported separately from the technical potential of conservation and the technical potential of load management. In addition, the final regulations contain a definition of the technical potential of demand-side resources.

3. Life Extension and Repowering

a. Background

In the proposed regulations, the Siting Council required electric companies to identify the technical potential of life extension and repowering at existing plants. The Siting Council notes that only the electric company can research and assess the potential for resource development at its existing plants. To encourage full consideration of this potential, the electric companies are required under the proposed regulations at 980 CMR 12.03(9)(b) to provide detailed data and information on this technical potential. In its Order, the Siting Council solicited comments on requiring electric companies to identify the technical potential for life extension or repowering at existing plants. EFSC 90-RM-100, pp. 34-35.

b. Discussion

Three electric companies submitted comments concerning the requirement to identify life-extension and repowering technical potential at existing plants. MECo and NEPCo argue that, unless particular projects are proposed for development by the electric company, disclosure of the technical potential of life extension and repowering at existing plants should not be required since such technical potential is not relevant to the electric company's initial filing and subsequent review (MECo/NEPCo Final Comments, p. 27). BECo also opposes this requirement. BECo argues that the life extension of a committed resource should be approved by the Siting Council as a committed resource, based on the electric company's demonstration of the cost-effectiveness of the unit's life extension (BECo Comments, p. 16). In addition, BECo asserts that the identification of the technical potential of repowering is not necessary since such options would be identified and included in the all-resource solicitation in some cases (id.). BECo further asserts that such a requirement would lead to disclosure of aspects of its bid well in advance of other potential bidders (id., pp. 16-17).

Contrary to the position of MECo, NEPCO, and BECo, WMECo supports the requirements of identifying multiple life-extension options for each existing resource and multiple repowering scenarios for existing plants (WMECo Comments, p. 26). WMECo maintains that life-extending or repowering some of its existing generating units may allow NU to meet its future capacity needs (id.).

The Siting Council rejects the arguments of MECo, NEPCo, and BECo regarding life extension and repowering. In the past, the Siting Council consistently has required electric companies to identify and evaluate a wide range of resource options, including life-extension options. See 1989 NEES Decision, 18 DOMSC at 348-371; 1989 BECo Decision, 18 DOMSC at 250-281; 1988

EUA Decision, 18 DOMSC at 111-131. This requirement merely is continued under the IRM process. Under the final regulations at 980 CMR 12.03(9)(b), the electric company is required to identify for existing units a range of improvements that may (1) extend the unit's life, (2) increase the efficiency or output of the unit, or (3) reduce the emissions of the unit. Further, the electric company's own resource proposals, as set forth in its initial resource portfolio, must be based on a thorough evaluation of all the electric company's resource options, including life extension and repowering. Thus, the arguments of BECo, MECo and NEPCo -- that the identification of the technical potential of life extension and repowering at electric company-owned plants is unnecessary -- ignore the electric company's obligation to identify and evaluate all resource options, particularly in cases where the electric company includes life extension or repowering in its initial resource portfolio.

The Siting Council also rejects BECo's argument that identification of the technical potential of repowering at existing units would in some way compromise the electric company's bid if that bid included repowering at an existing unit. First, by submitting the general information necessary to identify the technical potential for repowering, the electric company is in no way indicating whether it even would choose to pursue repowering through a bid. Second, in the case where an electric company chooses to pursue a repowering option and includes such option in its initial resource portfolio, the general information included in the identification of technical potential would not compromise the electric company's repowering bid. Such a bid would include far more detailed information than that required in our regulations.

Accordingly, the Siting Council finds that the requirements proposed in EFSC 90-RM-100 for identifying the technical potential of the life extension or repowering of existing plants are appropriate to ensure that electric companies identify and evaluate all available resource options, and such requirements are not changed in the final regulations.

III. ORDER OF INITIAL FILINGS

The Siting Council and the Department will issue a joint notice establishing filing dates for initial submissions by each electric company. In order to provide for an orderly and timely review of each case, such filings will be made on a staggered basis over a two-year period beginning April 1, 1991.

We find it appropriate to announce the sequence and dates for each electric company's first IRM filing so that the electric companies and other interested persons will have maximum notice for planning purposes. After reviewing the comments presented in this proceeding, each electric company's general characteristics, and the status of ongoing cases before the EFSC and the Department, we have determined that the affected electric companies shall file in the following sequence and on the following dates:[26]

	Electric Company	Draft Initial Filing	Initial Filing
1.	Massachusetts Electric Co./ New England Power Company	4/1/91	7/1/91
2.	Commonwealth Electric Co./ Cambridge Electric Light Co.	8/1/91	11/1/91
3.	Boston Edison Company	1/1/92	4/1/92
4.	Western Massachusetts Electric Company/ Northeast Utilities	4/1/92	7/1/92
5.	Fitchburg Gas and Electric Light Company	8/1/92	11/1/92
6.	Eastern Edison Company/ Montaup Electric Company	1/1/93	4/1/93

26/ This sequence of IRM filings is different from the one set forth by the Department in D.P.U. 89-239, p. 99. Here, WMECo and NU have been moved to fourth in the sequence of IRM filings, followed by Fitchburg, EECo and Montaup. In the Department's Order, WMECo and NU were scheduled for sixth in the sequence of IRM filings after Fitchburg, EECo and Montaup. The Siting Council, after consulting with the Department, makes this change based on WMECo's request to the Department to be moved up in the sequence of IRM filings.

IV. TRANSITION POLICY

As indicated in the previous section, the IRM process is scheduled to commence in April 1991,[27] and the draft and initial filings of each electric company will be staggered over a two-year period extending into 1993. However, at this time, each of the electric companies has a demand forecast and supply plan filing before the Siting Council. The Siting Council finds that it is appropriate to determine if and how such demand forecasts and supply plans will be reviewed by the Siting Council pending before that electric company's first IRM filing. In making this determination, the Siting Council considers each electric company's most recent demand forecast/supply plan decision and the status of the Siting Council's review of each electric company's demand forecast and supply plan filing.

MECo and NEPCo are scheduled first in the sequence of IRM filings with their draft initial IRM filing due on April 1, 1991. In light of this early filing date, and given the fact that the Siting Council approved the demand forecast of MECo and the supply plan of NEPCo in the 1989 NEES Decision (18 DOMSC 295), the Siting Council finds that it is appropriate not to review the currently-filed demand forecast and supply plan filing of MECo and NEPCo.

Turning to CECo and CELCo, the draft initial IRM filing of these electric companies is due on August 1, 1991. The Siting Council currently is reviewing the demand forecast of CECo and CELCo, but will not review CECo's and CELCo's supply plan in light of the August 1, 1991 filing date under IRM.[28]

27/ In advance of the first draft initial filing, the Siting Council and Department will specify the tables and forms to be used by electric companies in preparing the IRM filings.

28/ The Siting Council notes that in Commonwealth Electric Company, Cambridge Electric Light Company, and Canal Electric Company, 15 DOMSC 125 (1986), the Siting Council approved CECo's, CELCo's, and Canal's supply plan.

Decision, 18 DOMSC 201; 1988 EUA Decision, 18 DOMSC 73. The Siting Council will review Fitchburg's demand forecast and supply plan, and the other electric companies' pre-IRM demand forecasts and supply plans as well, under the standards of review that have been established in those recent decisions. Id.

V. ORDER

Accordingly, after notice, hearing, and consideration, it is hereby

ORDERED: That 980 CMR be amended to include a new Part 12.00, appended hereto, and that such new Part 12.00 be effective upon publication in the Massachusetts Register.

Frank P. Pozniak
Frank P. Pozniak
Hearing Officer

Dated this 30th day of November, 1990

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

980 CMR 12.00: RULES GOVERNING THE PROCEDURE BY WHICH ADDITIONAL RESOURCES ARE PLANNED, SOLICITED, AND PROCURED BY INVESTOR-OWNED ELECTRIC COMPANIES.

980 CMR 12.01 Purpose and Scope.

980 CMR 12.02 Definitions.

980 CMR 12.03 PHASE I: Initial Filing Requirements and Siting Council Review.

980 CMR 12.04 PHASE II: Solicitation Process and Project Evaluation. (See 220 CMR 10.04).

980 CMR 12.05 PHASE III: Resource Plan Filing Requirements and Department Review. (See 220 CMR 10.05).

980 CMR 12.06 PHASE IV: Resource Contracting Procedure. (See 220 CMR 10.06).

980 CMR 12.07 EFSC's Final Decision on the Supply Plan.

980 CMR 12.08 Other Rules.

980 CMR 12.00: RULES GOVERNING THE PROCEDURE BY WHICH ADDITIONAL RESOURCES ARE PLANNED, SOLICITED, AND PROCURED BY INVESTOR-OWNED ELECTRIC COMPANIES.

980 CMR 12.01 Purpose and Scope

(1) Purpose. The purpose of these regulations is to establish procedures by which additional resources are planned, solicited, and procured through an Integrated Resource Management process to meet an investor-owned electric company's obligation to provide reliable electrical service to customers in a least-cost, least-environmental-impact manner. These regulations establish the procedure for determining the need for additional resources.

(2) Scope.

(a) These regulations apply to the electric company's demand forecast, resource inventory, resource need forecast, and identification of the technical potential of demand-side resources and the technical potential of life extension and repowering of power plants.

(b) Affected utilities. These regulations apply to the following investor-owned electric companies:

1. Boston Edison Company
2. Cambridge Electric Light Company
3. Commonwealth Electric Company
4. Eastern Edison Company
5. Fitchburg Gas and Electric Light Company
6. Massachusetts Electric Company
7. Montaup Electric Company
8. New England Power Company
9. Northeast Utilities
10. Western Massachusetts Electric Company

(c) Each affected utility shall file IRM filings in compliance with 980 CMR 12.00. The requirements of 980 CMR 7.00 et. seq. shall not apply to the affected utilities or to the IRM filings (or intercycle forecast filings) of the affected utilities, except for 980 CMR 7.02(10), 7.04(2)(a)(c) and (d), 7.04(7)(c), 7.04(8) and (9), and 7.05(3).

980 CMR 12.02 Definitions

The terms set forth below shall be defined as follows in these regulations, unless the context otherwise requires. These definitions apply only to the regulatory process set forth in 980 CMR 12.00 and 220 CMR 10.00. Other terms relating to this regulatory process not included in this Section are defined in 220 CMR 10.02.

(1) All-Resource Solicitation shall mean the process by which electric companies solicit and evaluate supply-side and demand-side resources from project developers, as described in 220 CMR 10.04.

(2) Award Group shall mean the group of project proposals from the all-resource solicitation that is selected for final contract negotiation and signing or, in the case of electric company project proposals, for pre-approval pursuant to 220 CMR 9.00. The project proposals in the award group shall be presented to the Department for approval as part of the electric company's proposed resource plan.

(3) Base Case Scenario shall mean the electric company's most likely demand forecast scenario.

(4) Conservation shall mean a technology, measure, or action designed to decrease the kilowatt or kilowatthour requirements of an electric company.

(5) Customer shall mean any entity purchasing electricity from the host electric company on a retail basis.

(6) Demand-Side Resource or DSM shall mean any conservation, load management or fuel switching technology, measure, or action.

(7) Department or DPU shall mean the Department of Public Utilities.

(8) Department Regulations shall mean the regulations promulgated by the Department, at 220 CMR 10.00.

(9) Draft Initial Filing shall mean the preliminary initial filing submitted by the electric company for the purposes of pre-initial filing settlement discussions, pursuant to 980 CMR 12.03(4). The draft initial filing shall be sufficiently complete to allow for meaningful discussion of the issues. If agreement is reached on any of the components of the draft initial filing, those components can be submitted as part of the electric company's initial filing.

(10) EFSC or Siting Council shall mean the Energy Facilities Siting Council.

(11) Electric Company shall mean those affected utilities listed in 980 CMR 12.01(2)(b).

(12) Existing DSM Resource shall mean a resource that decreases the kilowatt or kilowatthour requirements of an electric company or that modifies the time pattern of customer capacity or energy requirements, and that has been installed at least one (1) month prior to the date of the initial filing.

(13) Existing Supply-Side Resource shall mean a supply-side resource that either (a) has been providing kilowatts or kilowatthours to the electric company at some time within the year beginning thirteen (13) months before and ending one (1) month before the submission of the initial filing, or (b) has provided kilowatts or kilowatthours to the electric company at some time other than thirteen (13) months before the submission of the initial filing and can be made operational without approval from the Department.

(14) Fuel Switching shall mean a measure or action designed to decrease the kilowatt or kilowatthour requirements of an electric company through the use of alternative fuels or technologies to meet the requirements of an end-use.

(15) Host Electric Company shall mean the electric company that conducts the all-resource solicitation for the purpose of procuring resources.

(16) Initial Filing shall mean the documents filed by the host electric company at the EFSC and Department at the beginning of Phase I. The initial filing shall include all of the documents described in 980 CMR 12.03(2).

(17) Initial Resource Portfolio shall mean the combination of resources proposed by the host electric company in the initial filing, pursuant to 980 CMR 12.03(6). The initial resource portfolio shall contain, at a minimum, the additional resources proposed by the electric company to meet the incremental resource need identified by the electric company in the initial filing in a least-cost, least-environmental-impact manner. The initial resource portfolio may include existing or planned electric company-owned resources, with or without proposed modifications, that the electric company wishes to subject to competitive ranking. The projects proposed in the

initial resource portfolio shall be compared with project proposals submitted by other parties in the all-resource solicitation. The information regarding the initial resource portfolio provided in the initial filing need not include price, method of cost recovery, or other cost information.

(18) Life Extension shall mean a specific program implemented in connection with an existing supply-side resource where such a program extends the retirement date of the existing supply-side resource.

(19) Load Management shall mean a measure or action designed to modify the time pattern of customer capacity or energy requirements, for the purpose of improving the efficiency of the electric company's operating system.

(20) Natural C&LM shall mean C&LM that will occur without the intervention of the electric company either as a direct supplier or as a purchaser of third party C&LM services.

(21) Peak Demand or Peak Load shall mean the maximum level of consumption of electrical energy in a system, or part thereof, expressed as the maximum megawatt load during a specified time period (e.g., day, week, month, year).

(22) Phase I shall mean the portion of the regulatory process set forth in 980 CMR 12.03 and 220 CMR 10.03.

(23) Phase II shall mean the portion of the regulatory process set forth in 220 CMR 10.04.

(24) Phase III shall mean the portion of the regulatory process set forth in 220 CMR 10.05.

(25) Phase IV shall mean the portion of the regulatory process set forth in 220 CMR 10.06.

(26) Planned Resource shall mean a resource that is contracted for or pre-approved but has not begun to provide kilowatts or kilowatthours to the electric company or decrease the kilowatt or kilowatthour requirements of the electric company or modify the time pattern of customer capacity or energy requirements.

(27) Pre-approval shall mean the Department procedures for pre-approval of resources pursuant to 220 CMR 9.00, D.P.U. 86-36-F, and D.P.U. 86-36-G.

(28) Project Proposal shall mean a proposal for providing a demand-side or supply-side resource to the host electric company through the all-resource solicitation. A host electric company's project proposals shall be set forth in the initial resource portfolio; other entities' project proposals shall be submitted in response to an RFP. A project proposal shall include all of the terms and conditions required by the host electric company's RFP. A project proposal may include a portion of a generating facility or DSM program, as well as the entire facility or program.

(29) Proposed Resource Plan shall mean the award group proposed by the electric company for Department review in Phase III, as well as all of the documentation required to describe the selection of the award group, pursuant to 220 CMR 10.05(2).

(30) Repowering shall mean a specific program implemented with respect to an existing supply-side resource where such program changes the combustion or generation configuration of the existing supply-side resource.

(31) Resource shall mean any facility, technology, measure, plan or action that either generates kilowatts or kilowatthours to meet the requirements of an electric company, decreases the kilowatt or kilowatthour requirements of an electric company, or modifies the time pattern of customer capacity or energy requirements for the purpose of improving the efficiency of the electric company's operating system.

(32) Resource Inventory shall mean the combination of existing and planned resources of an electric company.

(33) Supply-Side Resource shall mean a resource that provides kilowatts or kilowatthours to the electric company. Generation, transmission and distribution systems may be considered supply-side resources to the extent that they increase the total amount of kilowatts or kilowatthours that can be provided to the electric company to meet the needs of its retail customers.

(34) Technical Potential of Demand-Side Resources shall mean the sum of potential capacity and energy savings that may be achieved by installing all state-of-the-art, commercially available conservation, load management, or fuel switching technologies that yield the most energy and capacity savings for each end use in each customer class subsector, regardless of the cost or delivery mechanism. Technical potential should be based on the assumption that full market participation can be achieved and should not be limited by current or anticipated DSM programs.

(35) Technical Potential of Life Extension shall mean the kilowatts and kilowatthours provided by the continuation of existing supply-side resources beyond the retirement date of such resources resulting from state-of-the-art, available technologies for life extension, regardless of the cost of such continuation.

(36) Technical Potential of Repowering shall mean the kilowatts and kilowatthours provided by the change in the combustion or generation configuration of an existing supply-side resource resulting from state-of-the-art, available technologies for repowering, regardless of the cost of such repowering but recognizing the physical constraints of the plant site.

980 CMR 12.03 PHASE I: Draft Initial Filing and Initial Filing Requirements and Siting Council Review

(1) Frequency of Filing. Each electric company shall submit to the EFSC and the Department the filings identified below, pursuant to a schedule established by the EFSC and the Department. The filing schedule for each cycle after the first cycle shall be determined in the EFSC's final order of the previous cycle. In no event shall initial filings be more frequent than 18 months, nor less frequent than 30 months from the previous initial filing.

(2) Documents to be Filed.

(a) Draft Initial Filing. Each electric company shall submit a draft initial filing to the Siting Council and the Department eleven (11) weeks before the initial filing date established by the Siting Council and the Department. In addition, the draft initial filing shall be made available to any person who so requests for purpose of participation in discussions at the technical sessions or in settlement negotiations. The draft initial filing shall be sufficiently complete to allow meaningful discussion of the issues. If agreement is reached on any of the components of the draft initial filing, those components can be submitted as part of the electric company's initial filing.

(b) Initial Filing. Each electric company's initial filing shall contain the following documents.

1. Executive Summary. The Executive Summary shall be a non-technical summary of the information presented in each technical volume.

2. Technical Volumes.

A. The Demand Forecast shall include all of the information required by 980 CMR 12.03(5), and any other documentation that the electric company deems useful for EFSC review.

B. The Resource Inventory shall contain all of the information required by 980 CMR 12.03(7), and any other documentation that the electric company deems useful for EFSC review.

C. The Evaluation of Resource Need shall contain all of the information required by 980 CMR 12.03(8), and any other documentation that the electric company deems useful for EFSC review.

D. The Evaluation of Resource Potential shall contain all of the information required by 980 CMR 12.03(9), and any other documentation that the electric company deems useful for EFSC review.

E. The Resource Solicitation Request for Proposals shall contain all the information required by 220 CMR 10.03(6) and any other documentation that the electric company deems useful for Department review.

F. The Initial Resource Portfolio shall contain all of the information required by 980 CMR 12.03(6) and 220 CMR 10.03(5), and any other documentation that the electric company deems useful for EFSC and Department review.

G. The Pre-filing Settlement Package shall contain the results, if any, of the pre-filing settlement process, pursuant to 980 CMR 12.03(4) and 220 CMR 10.03(4), and any other documentation the electric company deems useful for EFSC and Department review of a proposed settlement.

(3) Notice and Participation.

The rules set forth below apply only to the regulatory process set forth in 980 CMR 12.00 and 220 CMR 10.00.

(a) Notice

1. At least eleven (11) weeks before the initial filing date established by the EFSC and the Department, the electric company shall submit a draft initial filing to the EFSC and Department whereupon the EFSC and Department shall issue an Order of Notice to inform the public about the electric company's draft initial filing, technical sessions and Phase I initial filing, and the deadline for filing written requests to the EFSC and Department to intervene as a party or to participate as an interested person.

2. Within ten (10) days of the issuance of the Order of Notice, the electric company shall publish the notice in at least one (1) newspaper of general circulation in the service territory, as approved by the EFSC and the Department, and send actual notice to any person that has filed a request for notice with the electric company. The EFSC and Department shall establish a deadline for filing requests to intervene and participate and shall include such deadline in the Order of Notice. The deadline for filing requests to intervene or participate shall be no less than ten (10) business days after the publication of the Order of Notice.

(b) Intervention and Participation. Any person who wishes to intervene as a party or participate as an interested person shall file a written request to the EFSC and Department to intervene as a party or participate as an interested person, pursuant to 980 CMR 1.05 and 220 CMR 1.03, before the intervention and participation deadline date set forth in the Order of Notice. The EFSC and the Department may, at their discretion, hold hearings to consider the requests for intervenor or interested person status.

(4) <u>Pre-Initial Filing Settlement Procedures</u>

(a) Technical Sessions

1. The electric company shall hold at least one (1) technical session at least eight (8) weeks before the initial filing date established by the EFSC and the Department.

2. The purpose of the technical session is to (a) provide a basis for exchange of information and clarification of the draft initial filing and (b) establish procedures and rules for further discussions designed to limit or settle issues, pursuant to 980 CMR 12.03(4)(b).

(b) Settlement Negotiations

1. The electric company shall enter into discussions with parties to the proceeding for the purpose of evaluating the electric company's draft initial filing and for the purpose of reaching agreement among the parties to the proceeding on all or some issues in the draft initial filing.

2. The purpose of the settlement negotiations is to facilitate the EFSC's and Department's coordinated review of the initial filing by (1) improving all parties' to the proceeding understanding of the electric company's draft initial filing, (2) reaching agreement among the parties to the proceeding to the maximum extent possible on the electric company's draft initial filing, (3) making agreed-upon improvements to the filing, and (4) identifying specific areas for adjudication, if necessary, before the EFSC, the Department, or both.

3. Any settlement, partial settlement, or contested settlement reached by parties to the proceeding shall be filed with the EFSC and the Department in the electric company's formal Phase I initial filing. Final approval of any settlement, partial settlement, or contested settlement

pertaining to the demand forecast, the resource inventory, evaluation of resource need, and evaluation of resource potential shall be subject to EFSC review. Final approval of any settlement, partial settlement, or contested settlement pertaining to the RFP or the electric company's initial resource portfolio shall be subject to Department review.

4. Discussions and positions taken by the parties to the proceeding during the course of settlement negotiations shall neither be admissible nor subject to discovery during any adjudicatory proceeding. Facts disclosed during such settlement negotiations may be subject to discovery during any adjudicatory proceeding.

5. Staff members from the EFSC or the Department may participate in the settlement negotiations, in the same role as the parties to the proceeding. Any EFSC or Department staff member that actively participates in the settlement negotiations shall be prohibited from advising the EFSC or Commission in its review of the initial filing, or from participating in subsequent proceedings involving the review of that filing. The EFSC or Department shall not be bound on any matter agreed to by EFSC or Department staff members during the settlement negotiations.

(c) Facilitation. The parties to the proceeding are encouraged to use an impartial entity to facilitate the settlement negotiations. The EFSC and Department may make staff members available for facilitation. EFSC or Department staff members who facilitate the negotiations shall be prohibited from advising the EFSC or Commission in their review of the initial filing, or from participating in subsequent proceedings involving the review of that filing. Facilitation expenses (e.g., those expenses incurred for facilitators, meeting rooms) shall be borne by the electric company.

(5) Demand Forecast

(a) Purpose and Scope. This section sets forth the requirements for forecasts of demand. Projections of the demand for electricity shall be based on substantially accurate historical information and reasonable statistical projection methods. The electric company shall demonstrate that the demand forecast is: reviewable, that is, it contains enough information and sufficient documentation to allow full understanding of the forecasting methodology; appropriate, that is, it uses a methodology that produces a forecast that is technically suitable to the size and nature of the electric company that produced it; and reliable, that is, it uses a methodology that provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. The demand forecast shall be subject to Siting Council review in Phase I, pursuant to this Section. Consistent with the findings on the demand forecast, the Siting Council, in its Order, may (1) adjust or modify an electric company's forecast of resource need for the all-resource solicitation, or (2) stay the IRM process.

(b) Contents of Forecast

1. Demand Forecast Characteristics. The base case demand forecast shall include historical data for a minimum of five (5) calendar years preceding the year in which the initial filing is submitted and projections for twenty (20) calendar years beginning with the year in which the initial filing is submitted. In the case of an electric company that receives electrical service or system-wide supply planning from affiliated companies that do business in other states as well as in Massachusetts, the electric company shall file two separate demand forecasts: one for its Massachusetts service territory, and a second for the entire electric operation of the affiliated company. The electric company shall provide the following information:

A. Total annual electrical energy demand for the electric company's service territory, with breakdowns for each of the customer classes specified in 980 CMR 12.03(5)(d);
B. Total seasonal peak demands for the electric company's service territory, with breakdowns for each of the customer classes specified in 980 CMR 12.03(5)(d), for both summer and winter seasons;
C. Annual service territory load factor;
D. Annual service territory load duration curves;
E. Service territory load profiles for representative days in both summer and winter seasons;
F. Estimated transmission and distribution losses; and

G. Capability responsibility based on NEPOOL practices and the electric company's reserve requirement.

2. Natural Conservation and Load Management. An electric company's projections of its demand for electricity shall include natural C&LM. The electric company shall quantify the effects of natural C&LM on demand, and include natural C&LM as a major determinant of demand. The electric company shall identify the following which are included in the demand forecast:

A. C&LM programs sponsored or mandated by federal, state, and local governments (e.g., building codes, appliance efficiency standards);
B. Market-induced C&LM; and
C. Market-induced self-generation (excluding sales to the company).

3. Natural Fuel Switching. An electric company's projections of its demand for electricity shall include projections of the natural switching of alternative fuels for electricity.

(c) Demand Forecast Methodology. The Siting Council does not prescribe a particular methodology that must be used by an electric company in forecasting demand. The methodology selected by an electric company must be reviewable, appropriate, and reliable. The electric company shall describe the following components of its forecast methodology for each year of the forecast period:

1. The major determinants of total annual electric energy demand and seasonal peak demand. Such description shall identify the source of the determinants and document how these determinants were incorporated in the demand forecast. At a minimum, the following determinants shall be described:

    A. Demographic data and economic activity pertaining to the electric company's service territory;
    B. The electric company's projections of its price of electricity and the price elasticity of demand for electricity;
    C. The electric company's estimate of the substitution of electricity for other fuels in competing end-uses;
    D. Behavioral factors which are expected to have a significant affect on electricity demand;
    E. Federal, state, or local policies that are expected to have a significant affect on electricity demand;
    F. Natural C&LM;
    G. Natural fuel switching; and
    H. Other relevant factors.

2. The sources and vintages of the major data components used in the demand forecast.

3. The methodologies used to acquire, organize, modify, and test the validity of data used in the demand forecast, and the techniques used to project electricity consumption based on such data.

4. The major models used in compiling the forecast including a description of the model logic and identification of the key variables affecting the model's outcome.

5. The level of confidence associated with key dependent and independent variables used in the electric company's models with a detailed explanation of the reasons in support of such level of confidence.

6. The major assumptions regarding the forecast of electricity demand with a detailed explanation of the reasons in support of these major assumptions.

(d) Customer Classes. Each demand forecast shall include separate forecasts of total annual electric energy demand and seasonal peak loads for each customer class. Commercial classes shall be identified by building type. Industrial classes shall be identified by two-digit SIC code or grouping of SIC codes. All customer classes shall be disaggregated by end-use as appropriate. Separate forecasts shall be provided for each of the following customer classes:

1. Residential without electric heating;
2. Residential with electric heating;
3. Total residential;
4. Commercial;
5. Industrial;
6. Street lighting;
7. Railway;
8. Sales for resale;
9. Losses, internal use, and unaccounted for; and
10. Any other customer class.

(e) Sensitivity Analyses

1. The demand forecast shall include sensitivity analyses of major assumptions contained in an electric company's forecast methodology.

2. The demand forecast shall include, in addition to the base case growth forecast, high demand growth and low demand growth scenario forecasts. Additional forecast analyses shall be provided by the electric company as appropriate. The high demand growth and low demand growth scenario forecasts shall include estimated annual energy and peak load growth rates over the forecast period, and a brief discussion of the key changes in the variables and assumptions relied on to produce the high, base case, and low demand growth forecasts.

(6) Initial Electric Company Resource Portfolio

(a) The initial resource portfolio shall be designed to meet the entire resource need identified by the host electric company in the evaluation of resource need filed pursuant to 980 CMR 12.03(8).

(b) The initial resource portfolio shall be designed to provide reliable electrical service to the electric company's customers at the least cost with the least environmental impact.

(c) For each resource in its portfolio, the electric company shall provide all the information proposed to be required of the RFP respondents to the all-resource solicitation pursuant to 220 CMR 10.00, and all the information required for DPU review of pre-approval rate treatment pursuant to 220 CMR 9.00, except for output price, method of cost recovery, and cost information.

(d) The electric company shall separately identify the following elements of its initial resource portfolio:

1. Resources that are proposed to be purchased from other entities and that have not yet been approved by the Department;
2. Resources that are proposed to be purchased from other entities and that are not subject to Department approval;
3. Electric company proposed modifications to generating units requiring pre-approval by the Department;
4. Additional electric company proposed generation facilities not yet pre-approved by the Department;
5. Additional electric company proposed DSM resources not yet existing or planned; and
6. Any existing or planned electric company-owned resource that the electric company proposes for its initial resource portfolio.

(7) Resource Inventory

(a) Purpose and Scope. This part sets forth the requirements for determining an electric company's resource inventory. The electric company shall identify separately existing supply-side resources; existing DSM resources; planned (i.e., resources that have DPU or FERC approval) supply-side resources; and planned DSM resources. The electric company shall apply attrition factors to the planned resources to account for the contingency that planned resources may not meet the electric company's expected commercial operation dates for such resources. The electric company may exclude an electric company-owned resource from the resource inventory and include such resource in its initial resource portfolio. All planned and existing resources shall be included in the resource inventory except for (1) those units, which due to extraordinary circumstances, are excluded by the Siting Council from an electric company's resource inventory, and (2) those electric company-owned units which the electric company demonstrates should be excluded from its resource inventory. In addition, the performance of existing resources shall be reviewed to determine whether each unit's performance has been evaluated appropriately in the filing. The resource inventory shall be compared to the demand forecast to determine the electric company's additional resource need, described in 980 CMR 12.03(8). To facilitate the EFSC review, the electric company shall provide the information set forth in 980 CMR 12.03(7)(b) for the five (5) calendar years preceding the year in which the initial filing is submitted, and the twenty (20) calendar years beginning with the year in which the initial filing is submitted. The resource inventory shall be subject to EFSC review in Phase I, pursuant to 980 CMR 12.03(7). Consistent with the findings on the resource inventory, the Siting Council in its Order, may adjust or modify the electric company's evaluation of resource need.

(b) Identification of Resources

1. The electric company shall summarize the diversity of the company's capacity and energy resources in its resource inventory in the following categories;

A. Resources owned fully or partially by the electric company relative to resources owned by other entities;
B. Supply-side resources relative to DSM resources;
C. For demand-side resources, conservation resources relative to load management resources and fuel switching resources;

D. For supply-side resources, fuel type;

E. For supply-side resources, plant type (base load, intermediate, or peaking); and

F. For supply-side resources, plant size and technology.

2. Inventory of Existing Supply-Side Resources. Each electric company shall identify its existing supply-side resources, and provide the following information for each identified existing supply-side resource:

A. Facility name and unit number, location, and owner;

B. Percentage and quantity of host electric company's ownership of output;

C. In-service date;

D. Nameplate capability rating (summer and winter);

E. Current NEPOOL capability rating (summer and winter);

F. Type of service (base, intermediate, peaking);

G. Total acreage of the facility site;

H. Annual production in kilowatthours;

I. Capacity factor;

J. Equivalent availability factor;

K. Forced outage rate;

L. Heat rate curve;

M. Technology and design, including major pollution control equipment;

N. Fuel types;

O. Capital costs;

P. Variable operating costs (both fuel and variable operation and maintenance costs, disaggregated);

Q. Fixed operation and maintenance costs;

R. Other costs such as waste disposal, decommissioning, insurance, and property taxes;

S. Permit restrictions which limit operation;

T. Environmental impacts such as airborne emission rates, water emission rates, solid waste disposal, hazardous waste disposal, water use, etc., reported in the same format that is required in RFP pursuant to 220 CMR 10.03(6); and

U. Remaining life of resource (anticipated expiration of equipment or contract without investment requiring pre-approval pursuant to 220 CMR 9.00), with full justification.

3. Inventory of Existing DSM Resources. Each electric company shall identify its existing DSM resources, and provide the following information for each identified existing DSM resource. The end-use of electricity and customer class shall be the basis for this inventory (e.g., industrial motors, residential water heating).

A. Annual energy and capacity savings for the lifetime of the resource, and the basis for the calculation of savings;

B. Impact on summer and winter peak demand, described in kilowatts, for the lifetime of the resource;

C. Technologies installed to obtain the foregoing savings;

D. Variable, operating, and maintenance costs;

E. Total incremental costs per kilowatt and kilowatthour; and

F. Measurement or monitoring procedures.

4. Inventory of Planned Supply-Side Resources. Each electric company shall identify its planned supply-side resources, and provide the following information for each identified planned supply-side resource:

   A. Facility name and unit number, location, and owner;
   B. Percentage and quantity of host electric company's ownership of output;
   C. Expected in-service date;
   D. Megawatt capability (summer and winter);
   E. All fuel types (indicate proportions);
   F. Type of service (base, intermediate, peaking);
   G. Annual production in kilowatthours;
   H. Capacity factor;
   I. Equivalent availability factor;
   J. Forced outage rate;
   K. Heat rate curve;
   L. Annual contract costs for energy and capacity;
   M. Anticipated retirement date or purchase agreement termination date;
   N. Status of power sales agreement or other contract between the host electric company and the project developer, specifying whether the contract has been approved by the appropriate agency;
   O. Status of fuel supply contracts and transportation;
   P. Status of all environmental and regulatory permits needed for the operation of the resource;
   Q. Status of DPU pre-approval, if required in the case of electric company-provided generation; and

R. Status of the financing and construction of all relevant structures needed for the operation of the resource.

5. Inventory of Planned DSM Resources. Each electric company shall identify its planned DSM resources, and provide the following information for each identified planned DSM resource. The electricity end-use and customer class shall be the basis for this inventory (e.g., industrial motors, residential water heating).

A. Annual energy and capacity savings for the lifetime of the resource, and the basis for the calculation of savings;

B. Estimated impact on summer and winter peak demand, described in kilowatts for the lifetime of the resource;

C. Technologies planned to be implemented to obtain savings;

D. Targeted market segments and end-uses, and the saturation level of the technology in such segments and end-uses prior to implementation of the resource;

E. Project details, including origin of the resource (i.e., specify solicitation or negotiation), project proponent, and the expiration date of the contract or termination date of the program;

F. Contracts the host electric company has with project developers, and the status of contract approval by the Department, or other appropriate regulatory authority having jurisdiction over the purchase;

G. Electric company DSM programs which include identified planned DSM resources. For such programs, the program title, a description of the program, pre-approval status, financial incentives for the electric company and participation levels anticipated; and

H. Description of major cost components of the electric company DSM programs, or contract costs for capacity and energy.

5. Attrition for Planned Resources. The electric company shall apply attrition factors to its inventory of planned supply-side resources and planned demand-side resources to account for the contingency that planned resources may not meet the electric company's expected commercial operation dates for such resources. The electric company shall provide sufficient documentation explaining and justifying the use of these attrition factors. The Siting Council shall review the attrition factors for planned resources.

(8) <u>Evaluation of Resource Need</u>

(a) Purpose and Scope. This part sets forth the requirements for identifying the electric company's need for additional resources to provide reliable electrical service to customers at the least-cost with the least-environmental-impact. The characteristics of the additional resource need shall be used in establishing the electric company's all-resource solicitation pursuant to 220 CMR 10.00. The Department shall allow for solicitations of economical energy as part of the all-resource solicitation. The evaluation of resource need shall be subject to Siting Council review in Phase I, pursuant to 980 CMR 12.03(8). Consistent with the findings on the demand forecast and the resource inventory, the Siting Council, in its Order, may adjust or modify the electric company's evaluation of resource need.

(b) Identification of Resource Need

1. The electric company shall identify the general characteristics of the resource need described by the difference between the electric company's demand forecast and the electric company's resource inventory.
2. The need for resources shall be summarized for each year of the ten (10) calendar years beginning with the year following the expected completion of Phase IV, in the following terms:

   A. kilowatts of summer capacity;
   B. kilowatts of winter capacity;
   C. kilowatthours of total annual energy requirements; and
   D. capability responsibility based on NEPOOL practices and the electric company's reserve requirement.

3. The electric company shall describe the general characteristics of the additional resource need for each year of the ten (10) calendar years beginning with the year following the expected completion of Phase IV. This description shall include the following characteristics:

   A. Equivalent availability needs;
   B. In-service date;
   C. On-peak, off-peak and seasonal production requirements;

D. Diversity objectives, including but not limited to:
   1) Resources owned fully or partially by the electric company relative to resources owned by other entities;
   2) Supply-side resources relative to DSM resources;
   3) For demand-side resources, conservation resources relative to load management resources and fuel switching resources;
   4) For supply-side resources, fuel type;
   5) For supply-side resources, plant type (base load, intermediate, or peaking); and
   6) For supply-side resources, plant size and technology.

E. Voltage control needs; and

F. Locational needs.

(9) Evaluation of Resource Potential

(a) Technical Potential of DSM

1. Purpose and Scope. This part sets forth requirements for identifying all DSM technical potential in the host electric company's service territory. The electric company's assessment of the technical potential of DSM shall identify DSM program opportunities. The identification of the technical potential of DSM shall be subject to EFSC review in Phase I, pursuant to this Section. The EFSC review shall focus on the electric company's process for identifying the technical potential of DSM.

2. Identification of Technical Potential of DSM. For each end-use with conservation, load management or fuel switching potential, the electric company shall identify and quantify the estimated additional capacity and energy savings associated with each such measure. For each type of DSM potential, the electric company shall estimate the energy and capacity savings assuming full installation of all technologies that yield the most energy and capacity savings, regardless of cost or delivery mechanisms and assuming full participation.

   A. The electric company shall identify and quantify the estimated capacity and energy savings for each customer class sector, subsector (e.g., rental housing, two-digit SIC codes).

   B. The electric company shall identify the most efficient potential conservation option, the most efficient potential load management option, and the most efficient fuel switching option for each end-use. For each end-use, the electric company shall provide the following information:

      1) Estimated energy and capacity savings for each end-use based on the full implementation of all conservation, load management and fuel switching options identified;

      2) Estimated value of end-user benefits in addition to the energy savings attributable to the installation of particular conservation, load management and fuel switching improvements; and

3) Total estimated savings for the electric company's service territory, described in terms of energy and peak capacity, with specifications of savings in transmission and distribution line losses, and reduced reserve requirements.

C. The electric company shall specify which of the above DSM technologies have been implemented in existing DSM resources.

(b) Technical Potential of Life Extension or Repowering.

1. Purpose and Scope. This Part sets forth the basic requirements for identifying all plant life extension or repowering potential. The electric company's assessment of technical potential of life extension or repowering will identify large blocks of power potentially available at existing power plants. The EFSC review shall focus on the electric company's process for identifying the technical potential of life extension or repowering.

2. Identification of Technical Potential of Life Extension or Repowering. For each plant with life extension or repowering potential, the electric company shall identify a wide range of options to modify the life, output and performance of the plant without regard to cost or time. For each option, the electric company shall describe the significant actions needed for life-extending or repowering a plant, based on known plant conditions and state-of-the-art,

commercially available technologies. For each plant that the electric company owns or has applicable rights to, the electric company shall provide:

A. Plant name and owner;
B. Output received by the electric company;
C. Existing fuel type and technology;
D. Type of service (base, intermediate, peaking);
E. Each potential option for life extension or repowering with the following information:
   1) Technologies and fuel type;
   2) Operating or environmental permits that are expected to be required;
   3) Necessary modifications;
   4) Types of service (base, intermediate, peaking);
   5) Length of extension of useful life;
   6) Capacity after life extension or repowering; and
   7) Improvements in performance factors.

(10) Review of the Initial Filing.

(a) EFSC Review.

1. The EFSC shall conduct an adjudicatory proceeding on the electric company's initial filing pursuant to 980 CMR 1.00.

2. The EFSC shall review each electric company's initial filing with respect to the demand forecast, the resource inventory, the evaluation of resource need, and the evaluation of resource potential. The EFSC findings regarding these issues shall be entered into the Department's

docket and adopted by the Department, unless the Siting Council issues an Order which stays the IRM process pursuant to 980 CMR 12.03(5)(a).

3. The EFSC shall complete its proceeding and issue an Order within four months of the electric company's initial filing date. Pursuant to 980 CMR 12.03(5)(a), the EFSC may issue an Order which stays the IRM process. If the EFSC does not issue an Order within four months, the electric company's initial filing with respect to these issues shall be deemed accepted by the Department.

4. The electric company shall revise its initial resource portfolio if the EFSC orders a material and substantial change to the initial resource portfolio resulting from the findings on the demand forecast, resource inventory, or evaluation of resource need. The electric company shall submit its revised initial resource portfolio within the time frame specified in the Department's Order on the initial filing, but no later than 60 days from the issuance of the Department's Order.

5. The Siting Council shall review the adequacy of the electric company's supply plan in the short run as part of its review of the initial filing. In the initial filing, the electric company shall demonstrate the adequacy of its supply plan to meet demand in the short-run. An electric company must demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies in the short run. If an electric company cannot establish

that it has adequate resources in the short run, the electric company shall demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative resources in the event of certain contingencies. The electric company shall compare its resource inventory, as identified pursuant to 980 CMR 12.03(7), with forecasted demand, as identified pursuant to 980 CMR 12.03(5), for the short run. For the purposes of the initial filing, the short run shall be defined as the time period extending four (4) calendar years beginning with the year in which the initial filing is submitted.

6. The EFSC's docket in a proceeding shall remain open until the Department completes its review in Phase IV pursuant to 220 CMR 10.06.

(b) Department Review. Pursuant to Department regulations, 220 CMR 10.03(7), the electric company shall submit its initial filing to the Department at the same time it submits its filing to the Siting Council. Pursuant to Department regulations, the Department shall be responsible for reviewing each electric company's initial filing to determine whether an electric company's RFP is in the public interest. Pursuant to Department regulations, the Department shall issue an Order on the electric company's initial filing within five months of the initial filing date.

980 CMR 12.04 PHASE II: Solicitation Process and Project Evaluation. See 220 CMR 10.04.

980 CMR 12.05 PHASE III: Resource Plan Filing Requirements and Department Review. See 220 CMR 10.05.

980 CMR 12.06 PHASE IV: Resource Contracting Procedure. See 220 CMR 10.06.

980 CMR 12.07 EFSC's Final Decision on the Supply Plan

The Siting Council shall issue its final decision on the supply plan upon completion by the Department of its review in Phase IV pursuant to 980 CMR 10.06. The Department's findings on an electric company's contracts and pre-approval filings in Phase IV shall be entered into the Siting Council's docket. If the Department approves such contracts and pre-approval filings, then the Siting Council shall accept the Department's findings as establishing that an electric company has a least-cost, least-environmental-impact supply plan as required by G.L. c. 164, sec. 69H. When the Department's findings are adopted by the Siting Council in the Siting Council's final decision on the supply plan, the Siting Council shall issue a final decision and close the docket in the proceeding.

980 CMR 12.08 Other Rules

(1) Intercycle Forecasts

(a) Purpose and Scope. This section sets forth the requirements for intercycle forecasts and supply plans which electric companies must file in each calendar year when the electric company is not required to submit an initial filing. The intercycle forecasts and supply plans shall be submitted in order that the Siting Council may review (1) any significant changes or proposed changes in the demand forecast, resource inventory, evaluation of resource need, evaluation of the technical potential of DSM, and evaluation of the technical potential of life extension or repowering, and (2) the adequacy of the electric company's supply plan in the short run. The Siting Council, in its discretion, may conduct an adjudicatory proceeding with respect to intercycle forecasts and supply plans pursuant to 980 CMR 1.00.

(b) Content of Forecasts. The electric company shall provide a narrative explanation of significant changes or proposed changes in the electric company's demand forecast, resource inventory, evaluation of resource need, and evaluation of resource potential. The Siting Council may require the electric company to include additional information in the intercycle forecast and supply plan if the demand forecast or any separate forecast contained therein was rejected by the Siting Council in the review of the previous initial filing. The electric company shall respond to any Orders set forth by the EFSC in the previous Phase I IRM final decision. Any planned supply-side resource or demand-side resource that has become operational since the previous review of the initial filing shall be identified in the intercycle forecast and supply plan. The electric company shall provide a comparison of the resource inventory and the demand forecast for the ten (10) calendar years beginning with the year in which the intercycle forecast and supply plan is submitted. The electric company shall demonstrate that it owns or has under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies in the short run. If an electric company cannot establish that it has adequate supplies in the short run, the electric company shall demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies in the event of certain contingencies. The electric company shall compare the resource inventory with demand forecast for the short run. For the purposes of the intercycle forecast and supply plan, the short run shall be defined as the time period extending four (4) calendar years beginning with the year in which the intercycle forecast and supply plan is submitted.

(2) Exceptions. The EFSC, where it deems appropriate, may grant an exception to any provision of these regulations.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of MASSPOWER, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	EFSC 89-100A

FINAL DECISION

Frank P. Pozniak
Hearing Officer
December 19, 1990

On the Decision:

Robert J. Harrold

APPEARANCES: John A. DeTore, Esq.
Timothy F. Ferris, Esq.
Keohane, DeTore, & Keegan
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Boston, Massachusetts 02110
FOR: MASSPOWER, Inc.
<u>Petitioner</u>

Paul B. Dexter, Esq.
LeBoeuf, Lamb, Leiby, & MacRae
260 Franklin Street
Boston, Massachusetts 02110
FOR: Bay State Gas Company
<u>Intervenor</u>

The Energy Facilities Siting Council hereby APPROVES the petition of MASSPOWER, Inc. to construct a 240 megawatt bulk generating facility and ancillary facilities in Springfield, Massachusetts.

I. BACKGROUND

On August 10, 1990, the Energy Facilities Siting Council ("Siting Council") conditionally approved the petition of MASSPOWER, Inc. to construct a 240 megawatt ("MW") cogeneration facility and certain ancillary facilities in the City of Springfield. MASSPOWER, Inc., 20 DOMSC 301 (1990). The approval was conditional because the Siting Council determined that MASSPOWER had not fully demonstrated the need and viability of the proposed project. As a result, the Siting Council approved MASSPOWER's petition subject to the following conditions: (1) to demonstrate the need for the project, MASSPOWER was required to submit one or more signed and approved power sales contracts with Massachusetts utilities for a total of approximately 54 MW;[1] and (2) to demonstrate the viability of the project, MASSPOWER was required to submit (a) an executed turnkey construction agreement ("TCA") and an agreement with Partyka Resource Management Company for the siting of its proposed switchyard, and (b) an executed operation and maintenance ("O&M") agreement. Id., at 335, 358-359, 368-370. In addition, with respect to project viability, the approval of MASSPOWER's proposed project was contingent on the Siting Council's approval of the natural gas pipeline proposed to serve MASSPOWER. Id., at 368-370. This pipeline was proposed to be constructed by the Bay State Gas Company ("Bay State"), and was reviewed by the Siting Council in EFSC 89-13.

1/ This is the approximate amount of power bid by MASSPOWER in response to a request of Western Massachusetts Electric Company ("WMECo").

In response to these conditions, on November 19 and December 6, 1990 MASSPOWER submitted a number of documents to demonstrate its compliance. The next section contains a discussion of MASSPOWER's compliance with the conditions.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources to meet reliability or economic efficiency objectives. The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

Although the Siting Council found that MASSPOWER had established that New England needs at least 240 MW of additional energy resources for reliability purposes beginning in 1992, the Siting Council also found that MASSPOWER had not established that benefits to the Commonwealth are of sufficient magnitude to justify construction of the facility. MASSPOWER, Inc., 20 DOMSC at 335. Therefore, the Siting Council found that MASSPOWER had not demonstrated a need for additional energy resources. Id., at 336. Accordingly, the Siting Council determined that MASSPOWER would fully meet the need standard only if it enters into a certain level of power supply contracts with Massachusetts utilities and these contracts are approved by the Department of Public Utilities ("DPU"). Id.

The Siting Council found that MASSPOWER would demonstrate a need for additional energy resources if: (1) MASSPOWER presents to the Siting Council (a) a signed and approved contract with the Boston Edison Company ("BECo") for the approximate level of power bid by MASSPOWER; or (b) a signed and approved contract with WMECo for the approximate level of power bid by MASSPOWER; or (c) a signed and approved contract with these Massachusetts utilities or others, which in total amount to a level approximating at least that bid to WMECo; and (2) the Siting Council staff verifies that the response to (1) is complete and adequate. Id.

On December 6, 1990 the DPU approved a signed contract between BECo and MASSPOWER for 100 MW of power.[2] In past cases, the Siting Council has accepted signed contracts approved by the DPU as evidence of Massachusetts benefits. Altresco-Pittsfield, 17 DOMSC 351, 366-367 (1988); Northeast Energy Associates, 16 DOMSC 335, 358-360 (1987). Thus, the Hearing Officer verifies that the response to the need condition is complete and adequate.

Based on the foregoing, the Siting Council finds that MASSPOWER has established that benefits to the Commonwealth are of sufficient magnitude to justify construction of the facility consistent with the energy needs, resource use and development policies of Massachusetts. Accordingly, the Siting Council finds that MASSPOWER has demonstrated a need for additional energy resources.

B. Project Viability

1. Construction

In order to meet the first test of viability, a facility proponent has been required to establish (1) that the project is financiable, and (2) that the project is likely to be constructed within applicable time frames and capable of meeting performance objectives. MASSPOWER, Inc., 20 DOMSC at 352; Altresco-Pittsfield, 17 DOMSC at 378.

In the MASSPOWER decision, the Siting Council found that MASSPOWER had established that its proposed project is financiable (20 DOMSC at 356). However, the Siting Council also found that MASSPOWER had not established that the project is

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2/ The DPU approval hereby is moved into evidence as Exhibit HO-N-31. The executed contract between MASSPOWER, Inc. and BECo hereby is moved into evidence as Exhibit HO-N-32.

likely to be constructed so that the project will actually go into service as planned. Id., at 358. Therefore, the Siting Council found that MASSPOWER had not demonstrated that its proposed project meets the Siting Council's first test of viability. Id. Accordingly, the Siting Council determined that MASSPOWER would fully meet the first test of viability only if it enters into an appropriate TCA and enters into a final agreement which allows it to site the proposed switchyard. Id., at 359.

In response to these conditions, MASSPOWER presented to the Siting Council an executed TCA with the Bechtel Power Corporation ("Bechtel Power").[3] That TCA requires Bechtel Power to provide design, engineering, procurement, construction, and performance testing services associated with the proposed facility (Exh. HO-PV-17B, p. 1). In addition, the TCA includes a fixed price provision with performance milestones and a guaranteed completion date based on a construction schedule of approximately 27 months (id., pp. 7, 34-36; see MASSPOWER, Inc., 20 DOMSC at 356-357). Further, the TCA includes bonus/penalty provisions for early or late delivery, and similar provisions based on electrical output and heat rate performance (Exh. HO-PV-17B, pp. 66-74). The Siting Council notes that MASSPOWER had previously demonstrated that Bechtel Power has achieved a high level of experience as a builder of power plants and ancillary facilities. See MASSPOWER, Inc., 20 DOMSC at 357.

In the MASSPOWER decision, the Siting Council also noted that construction of the proposed facility was predicated on acquisition of all sites, yet a final agreement for the site of the proposed switchyard had not been secured. Id., at 358. Here, MASSPOWER has presented a finalized permanent easement agreement which provides for the construction, location, and

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3/ The executed TCA hereby is moved into evidence as Exhibit HO-PV-17B. MASSPOWER, Inc. has requested confidential treatment of this document, and such treatment hereby is granted.

maintenance of the proposed switchyard.[4]

Based on the foregoing, the Siting Council finds that MASSPOWER's executed TCA with Bechtel Power, and the finalized permanent easement pertaining to the proposed switchyard, provide reasonable assurances that the project is likely to be constructed on schedule and be able to perform as expected.

Accordingly, the Siting Council finds that MASSPOWER has demonstrated that its proposed project meets the Siting Council's first test of viability.

2. Operations and Fuel Acquisition

In the MASSPOWER decision, the Siting Council found that MASSPOWER had not demonstrated that its proposed project had met either element of the Siting Council's second test of viability (20 DOMSC at 368). In order to meet the second test of viability, a facility proponent has been required to establish (1) that its project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that its fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements. Id., at 352; Altresco-Pittsfield, 17 DOMSC at 378.

With respect to the first element of the foregoing project viability test, the Siting Council found that MASSPOWER has demonstrated that the proposed project is likely to be a viable source of energy only if MASSPOWER executes an appropriate O&M agreement which includes financial incentives and/or penalties which ensure reliable performance over the life of the unit. MASSPOWER, Inc., 20 DOMSC at 361, 370. Here, MASSPOWER presented a finalized O&M agreement with the General

4/ The executed easement agreement hereby is moved into evidence as Exhibit HO-S-8. MASSPOWER, Inc. has requested confidential treatment of this document, and such treatment hereby is granted.

Electric Power Generation Services ("GE").[5] That agreement requires GE to provide both mobilization and operations services to the proposed facility (Exh. HO-PV-27). In addition, that agreement specifies bonus/penalty provisions based on equivalent availability and heat rate performance, and provides for an evaluation of GE's overall performance by MASSPOWER (id., pp. 20-22). In a previous case, the Siting Council emphasized the importance of bonus/penalty provisions with respect to a facility's O&M agreement. Altresco-Pittsfield, 17 DOMSC at 381-382.

The O&M agreement between MASSPOWER and GE has set forth appropriate performance objectives for the proposed facility. In addition, MASSPOWER has previously established that GE has achieved a high level of O&M experience including O&M responsibilities for the Ocean State power plant, the Altresco-Pittsfield cogeneration facility, and five other combined cycle generating facilities. See MASSPOWER, Inc., 20 DOMSC at 359-360.

Accordingly, based on the foregoing, the Siting Council finds that MASSPOWER has established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. Therefore, the Siting Council finds that MASSPOWER has met the first element of the second test of viability.

With respect to the second element of the foregoing project viability test, the Siting Council found that MASSPOWER would be able to establish that its fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements only if the Siting Council approves the Bay State pipeline proposed to serve MASSPOWER. Id., at 368-370.

5/ The executed O&M agreement hereby is moved into evidence as Exhibit HO-PV-27. MASSPOWER, Inc. has requested confidential treatment of this document, and such treatment hereby is granted.

The Bay State pipeline project was conditionally approved by the Siting Council on October 12, 1990. Bay State Gas Company, EFSC 89-13 (1990). In that decision, the Siting Council found that the need for the Bay State pipeline would be established once MASSPOWER had met its power sales requirements set forth in the MASSPOWER decision. Id., pp. 11, 19, 84. As set forth in Section II.A, above, the Siting Council found that MASSPOWER had met the condition regarding the filing of executed power supply contracts. Therefore, the Siting Council finds that the need for the proposed Bay State pipeline is established.

Accordingly, based on the foregoing, the Siting Council finds that MASSPOWER has established that its fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of its power sales agreements. Therefore, the Siting Council finds that MASSPOWER has demonstrated that its proposed project meets the second test of viability.

In sum, the Siting Council has found that MASSPOWER has demonstrated that: (1) its proposed project is financiable and provides reasonable assurances that it is likely to be constructed on schedule and be able to perform as expected; and (2) its proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and that its fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of its power sales agreements.

Accordingly, based on the foregoing, the Siting Council finds that its proposed project is likely to be viable as a source of energy.

III. DECISION AND ORDER

Based on the foregoing, the Siting Council finds that the MASSPOWER has complied with the conditions set forth in the MASSPOWER decision, and that the construction of the proposed generating facility and ancillary facilities is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Council hereby APPROVES the petition of MASSPOWER, Inc. to construct a 240 MW cogeneration facility and certain ancillary facilities in the City of Springfield.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

Dated this 19th day of December, 1990.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of December 19, 1990 by the members present and voting. Voting for approval of the Tentative Decision as amended: Barbara Kates-Garnick (for Mary Ann Walsh, Secretary of Consumer Affairs and Business Regulation); Joellen D'Esti (for Alden S. Raine, Secretary of Economic Affairs); Robert Roach (for John P. DeVillars, Secretary of Environmental Affairs); Sarah Wald (Public Environmental Member); and Michael Ruane (Public Electricty Member).

Barbara Kates-Garnick

Barbara Kates-Garnick
Acting Chairperson

Dated this 19th day of December, 1990.

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Nantucket Electric Company for Approval of its 1990 Long-Range Forecast of Electric Requirements and Resources	EFSC 90-28

FINAL DECISION

Sue Nord
Hearing Officer
May 17, 1991

On the Decision:

Robert Graham

APPEARANCES: Robert J. Keegan, Esq.
David S. Rosenzweig, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, Massachusetts 02110
FOR: Nantucket Electric Company
Petitioner

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TABLES:

The Energy Facilities Siting Council hereby APPROVES the 1990 demand forecast and APPROVES the 1990 supply plan of Nantucket Electric Company.

I. INTRODUCTION

A. Background

Nantucket Electric Company ("Nantucket" or the "Company") is a small investor-owned utility engaged in the generation, distribution, and retail sale of electricity on the Island of Nantucket ("Island"), an area of approximately 26 square miles located approximately 25 miles from Cape Cod, Massachusetts. In 1990, the Company sold approximately 80,151 megawatthours ("MWH") of electricity and experienced a peak demand of 18.8 megawatts ("MW") (Exh. HO-4, p. 1). Nantucket is unique among Massachusetts electric utilities in that it is not interconnected with the New England Power Pool ("NEPOOL") or any other electric company or system (Exh. NAN-1, p. 1).

In 1990, approximately 67.4 percent of Nantucket's annual sales were to the residential sector, 32.3 percent to the commercial sector and 0.3 percent to the streetlighting sector (Exh. HO-4, p.1). The Company has no industrial load (Exh. NAN-1, pp. 4-1, 5-26). Nantucket has been a winter-peaking system since 1985 with the exception of 1990, when the Company's winter peak fell significantly (Exh. HO-G-5a).

In its most recent review of Nantucket's demand forecast and supply plan, the Siting Council approved the Company's demand forecast subject to conditions[1] and rejected the Company's supply plan. Nantucket Electric Company, 15 DOMSC 363 (1987) ("1987 Nantucket Decision"). In that decision, the Siting Council found that Nantucket had not established that (1) its supply plan was adequate in the short run, and (2) its supply planning process ensured a least-cost, least-environmental-impact supply for its customers

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1/ The Siting Council reviews Nantucket's compliance with these conditions in Sections II.D and III.E, below.

(Id., at 390).

B. Procedural History

Nantucket filed its 1990 demand forecast and supply plan ("1990 Forecast and Supply Plan") with the Siting Council on April 4, 1990 (Exh. NAN-1). On April 17, 1990, the Hearing Officer issued a Notice of Adjudication for the 1990 Forecast and Supply Plan and directed Nantucket to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company subsequently submitted confirmation of publication and posting.

On June 12, 1990, Jane Walton filed a petition to participate as an interested person in the proceeding. On June 20, 1990, the Siting Council issued a procedural order granting Ms. Walton's petition to participate in the proceeding as an interested person. The Siting Council received no petitions to intervene in the proceeding.

The Siting Council held evidentiary hearings on October 17 and 23, 1990. Nantucket presented three witnesses: Dr. John Stutz of Tellus Institute ("Tellus"), who testified regarding Nantucket's demand forecast; Richard LaCapra of LaCapra Associates, who testified regarding Nantucket's supply plan, conservation and load management ("C&LM") plan and load research efforts; and Robert Hawkins, president of Nantucket, who testified regarding Island-specific developments and the Company's financial situation.

The Hearing Officer entered 102 exhibits into the record, largely composed of Nantucket's responses to information and record requests. Nantucket entered 2 exhibits into the record.

Pursuant to a briefing schedule established by the Hearing Officer, Nantucket filed its brief on November 13, 1990. The Siting Council issued supplemental information requests on December 28, 1990. The Company's final responses to information requests were received by the Siting Council on January 25, 1991.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" (G.L. c. 164, sec. 69H), the Siting Council determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Massachusetts Municipal Wholesale Electric Company, 20 DOMSC 1, 14 (1990) ("1990 MMWEC Decision"). Boston Edison Company, 15 DOMSC 287, 294 (1987) ("1987 BECo Decision").

B. Energy Forecast

1. Overview

Nantucket stated that it forecasted annual energy requirements for the residential and commercial sectors using detailed end-use models (Exh. NAN-1, pp. 1-9 to 1-11). The Company indicated that it used a linear time series analysis to forecast annual streetlighting sales, which comprise a very small share of the Company's annual sales (id., pp. 3-21; Tr. 1, pp. 99-100).

Nantucket stated that its current end-use-based approach for forecasting residential and commercial energy sales represents a substantial departure from previous filings in terms of forecast methodology (Exh. NAN-1, p. 3-29). The record indicates that the Company previously forecasted annual electricity sales using econometric techniques (Exh. HO-1, Vol. 2).

Nantucket explained that it retained the services of Dr. Stutz of Tellus, an energy consulting firm, to develop its current forecast methodologies (Exh. NAN-1, p. 1-9). Nantucket stated that the Tellus approach to forecasting electricity demand "is based on the premise that aggregate energy requirements and peak demand can best be understood, and the impacts of the various factors driving growth accounted for, if the forecast is a composite of individual analyses of the major end-uses" (id., p. 3-5).

Dr. Stutz stated that end-use models have several inherent advantages relative to econometric and time series-based techniques for forecasting energy demand (id., pp. 3-29 to 3-30; Tr. 1, pp. 21-22). Dr. Stutz further stated that it is essential to disaggregate forecasts by end-use in order to fully integrate C&LM programs into the Company's supply planning process, since C&LM programs are inherently end-use specific (Exh. NAN-1, p. 3-30; Tr. 1, p. 21).[2] The Company stated that given these advantages over econometric and time series techniques, end-use based demand forecasting has become standard practice in the electric utility industry (Exh. NAN-1, p. 3-29).

The Company stated that two recent developments have made it possible to develop end-use forecasts for Nantucket at this time: (1) the availability of two recent studies of economic and

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2/ The Company incorporated natural C&LM in its residential and commercial end-use models by including projections for improvements in appliance efficiencies and energy intensities (Exh. NAN-1, pp. 3-16 to 3-19) (see Sections II.B.4 and II.B.5, below). Nantucket incorporated Company-sponsored C&LM into its energy and peak forecasts by subtracting estimates for such C&LM from the Company's unadjusted forecasts (id., pp. 3-27 to 3-28) (see Section III.B.2, below).

demographic trends for the Island;[3] and (2) the completion of surveys of current residential and commercial end-use saturations, which serve as a starting point for the analysis (id., pp. 3-1, 3-30).

While endorsing the use of end-use based models, the Company cautioned that "end-use based forecasting is arguably the most complex and difficult approach to forecasting" as well as the most data-intensive (id., p. 3-30). The Company further noted that its current forecast "is the 'first word' and not the 'last word' on end-use forecasting for Nantucket" and that "it can and will be refined and improved in the future" (id.).

As shown in Table 1, in its base case, Nantucket projects annual energy sales, unadjusted for Company-sponsored C&LM, to increase from 82,324 MWH in 1988 to 111,909 MWH in 2000 and 130,557 MWH in 2008, a compound annual growth rate of approximately 2.3 percent (id., Table 1-2, p. 3-3).[4] Data provided by the Company indicates that, historically, Nantucket's annual load has been highly volatile, particularly in the residential sector, which grew at an average rate of 1.2 percent between 1979 and 1983 and 11.0 percent between 1983 and 1988 (id., p. 3-8).

A detailed description and analysis of the individual forecasts which together comprise the Company's energy forecast are provided in the following sections.

3/ The reports identified by the Company are (1) "The Fiscal and Economic Impacts of Growth on the Island of Nantucket," prepared for the Nantucket Land Council by RKG Associates (June 1989) ("RKG Report") (Exh. HO-G-1a), and (2) "Nantucket Growth Strategies," prepared for the Nantucket Planning and Economic Development Commission by Herr & Associates and Netter & Associates (August 4, 1989) ("Herr Report") (Exh. HO-G-1b).

4/ After adjusting for projected Company-sponsored C&LM, Nantucket, in its base case, forecasts annual energy sales to increase to 108,084 MWH in 2000 and 126,732 MWH in 2008, an annual growth rate of 2.2 percent (Exh. NAN-1, p. 3-29, Chapter 3, Appendix A, Table 1-2). See Section III.D.2.a.iii, below, for a description of the Company's C&LM programs.

2. Economic and Demographic Forecast

a. Description

Dr. Stutz stated that it was not necessary for the Company to develop its own economic/demographic forecast because the Herr and RKG reports, two comprehensive reports on the economic and demographic future of the Island, recently had been prepared for public agencies on the Island (Exhs. HO-G-1a, HO-G-1b; Tr. 1, p. 27). These reports include historical information and projections for a variety of demographic indicators, including seasonal and year-round population, employment, dwelling units, tax revenues, tourism, development and land use, and commercial activity (Exhs. HO-G-1a, HO-G-1b, NAN-1, pp. 3-11 to 3-13; Tr. 1, pp. 34-37, 43-47, 57-62).

Nantucket stated that projections of economic and demographic data taken from the Herr and RKG reports served as key inputs in the Company's forecasts of residential and commercial electricity sales (Exh. NAN-1, pp. 3-11 to 3-13). Specifically, the Company stated that it relied on the Herr and RKG reports for projections of (1) the number of residential dwellings, the major "driver" of its residential sales model, and (2) seasonal employment, the key "driver" of its commercial sales model (id., pp. 3-11 to 3-14, 3-18).

Nantucket indicated that both the Herr and RKG reports contain several scenarios of demographic and economic factors (Exhs. HO-G-1a, HO-G-1b). The record indicates that each of these scenarios is based on an alternative view of potential future development patterns on the Island (id.). Nantucket stated that it chose to develop electricity sales forecasts using data from three of these scenarios (Exh. NAN-1, pp. 3-11). The Company identified these scenarios as: "Herr Eight," "Herr No Cap" and "RKG No Limit" (id.). The "Herr No Cap" and "RKG No Limit" scenarios both assume the continuation of historical growth trends and therefore exhibit significantly higher growth than "Herr Eight" (Exh. NAN-1, pp. 3-11 to

3-13).[5] The Company stated that it believed that "Herr Eight" was the most likely scenario because it reflected current Town plans to control growth on the Island (id., p. 1-10; Tr. 1, pp. 26, 28).

Dr. Stutz stated that he did not analyze projected electricity demand for any scenarios with lower projected growth than the "Herr Eight" scenario because he believed that the only scenario fitting that category (identified by the Company as "Herr Four") was unrealistically low (Exh. HO-D-1; Tr. 1, p. 27).

The Company demonstrated that, in combination with assumptions regarding appliance saturation and appliance efficiency, it developed multiple forecasts for residential and commercial electricity sales based on the aforementioned "Herr Eight," "Herr No Cap" and "RKG No Limit" economic/demographic scenarios (Exh. NAN-1, pp. 3-11, 3-14, 3-18 to 3-21). Detailed descriptions and analyses of the Company's selection of assumptions for its low, base and high residential and commercial sales forecasts are provided in Sections II.B.4 and II.B.5, below. See Table 2 for a summary of the base case forecast by customer class.

The Company stated that it based its base case and low case residential and commercial demand forecasts on the "Herr Eight" scenario, and its high case residential and commercial demand forecast on the "Herr No Cap" scenario (id., pp. 3-17, 3-21). The Company stated that it did not utilize the "RKG No Cap" scenario in its final choice of low, base and high electricity sales forecasts because it believed that, while for the next five to ten years such growth is conceivable, the number of residential dwellings at the end of the forecast period under the "RKG No Cap" scenario is unrealistically high (id., p. 3-17).

5/ For example, the record includes the following estimates of the number of residential dwellings in 2008 under the three scenarios: "Herr Eight," 9,570; "Herr No Cap," 10,577; and "RKG No Limit," 13,836 (Exh. NAN-1, p. 3-12). The record indicates that there were 6,350 residential dwellings on Nantucket in 1988 (id.).

b. Analysis

Unlike most electric utility service territories, Nantucket's service territory is a discrete demographic area. Thus, the Company is able to avoid problems frequently experienced by utilities that apply demographic and economic studies which reflect only a portion of their service territories to their service territories as a whole. Here, the Siting Council notes that it is not necessary for the Company to develop its own economic/demographic forecasts when up-to-date, reliable, territory-specific studies such as the Herr and RKG reports are available.

The Siting Council generally commends the Company's use of multiple scenarios as a means of analyzing the uncertainty inherent in the determinants of future electric demand in the residential and commercial sectors. Based on the record, the Company's choice of "Herr Eight" as its base case scenario is sound. However, the Company erred in also using "Herr Eight" as its low case scenario. By employing the same economic/demographic scenario for both its base and low cases, the Company fails to examine the possibility of a slower growth rate on the Island than that set forth in "Herr Eight".[6]

With the above exception, the Company utilized a reasonable and well-documented set of economic and demographic forecasts as inputs for its demand forecast. Accordingly, the Siting Council accepts Nantucket's methodologies for forecasting economic and demographic factors.

However, the Siting Council ORDERS Nantucket in its next filing to utilize distinct economic/demographic scenarios for its base, low and high case forecasts of annual electricity demand.

6/ For example, the Company could have used the Herr Four scenario or a lower buildout variant of Herr Eight as a low case. It also could have developed its own variant of these or other scenarios with little effort.

3. Electricity Price Forecast

a. Description

Nantucket did not provide an electricity price forecast in this proceeding. The Company stated that current and projected electricity prices, as well as price and income elasticities, are not explicitly incorporated as inputs in its demand forecast (Exh. HO-D-18; Tr. 1, p. 91). In addition, Nantucket did not incorporate into its demand forecast a forecast of factors such as fuel prices which could influence electricity prices.

The Company stated, however, that it did incorporate the effects of potential changes in electricity prices, relative to alternatives, into its residential and commercial end-use models in an implicit manner through the inclusion of alternative scenarios for appliance saturation levels and appliance efficiencies (Exh. HO-D-18). The Company provided two scenarios for projected residential space and water heating penetrations, as well as two scenarios for projected commercial appliance efficiencies (Exh. NAN-1, pp. 3-14 to 3-17, 3-20 to 3-21). Specifically, the Company stated that the case where electricity prices rise relative to alternative fuel prices is represented by its low case demand forecast, wherein electric space heating and water heating saturations are low and end-use efficiencies are high (id.). The Company further stated that the case where electricity prices decline relative to alternative fuel prices is represented by its base case and high case demand forecasts, wherein electric space heating and water heating saturations are high and end-use efficiency gains are modest (id.).

Dr. Stutz justified Nantucket's failure to explicitly include price as an input to the demand forecast by stating: "My experience has been that where price has been incorporated directly, that the problems of incorporating it and the problems of forecasting the prices themselves combine to make the forecast worse rather than better" (Tr. 1, p. 91). Dr. Stutz explained that Nantucket-specific price elasticities currently are not available (id., pp. 97-98). Dr. Stutz further stated that it would be inappropriate to use elasticities derived by NEPOOL or another electric company because Nantucket's heterogeneous customer mix makes it difficult to generalize about customer price response, and price elasticities can vary significantly both between service territories and within a given service territory over time (id.).

However, Dr. Stutz acknowledged that there is no rigorous way to translate specific electricity price changes into specific changes in appliance saturations and appliance efficiencies or vice versa (id., pp. 95-96). Further, the record indicates that Nantucket was granted a substantial rate increase which went into effect on June 29, 1989 (Exhs. HO-G-18a, HO-G-18b).[7] The Company's witness, Mr. LaCapra, stated that "to my knowledge, there has never been so great a rate shock in New England" (Tr. 2, p. 2-14). Finally, the Company has stated its intention to pursue an additional rate increase in the near future (Exh. HO-S-36).

b. Analysis

In the previous Nantucket filing reviewed by the Siting Council, the Company incorporated price into its demand forecast but failed to differentiate price by customer sector. 1987 Nantucket Decision, 15 DOMSC at 367, 376. In that decision, the Siting Council stated that "an appropriate forecast model must break out the price term by major class." Id. at 376. The Siting Council ordered Nantucket, in Condition 7, to "test and as appropriate use sales forecast models based on past and assumed future prices of electricity broken out by major customer class." Id. at 376.

In the instant case, the Company not only failed to comply with Condition 7 of the previous decision (see

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7/ The Company's calculations indicate that in January 1990 an existing residential heating customer would pay approximately 50 percent more under the new rates than under the old rates (Exh. HO-RR-8). The record also demonstrates that all new residential customers are subjected to a time-of-use rate under which peak rates are 21.25 cents per KWH and off-peak rates are 1.66 cents per KWH (Exh. HO-G-18b, Rate R-2).

Section II.D, below), but in fact took a significant step backward from its previous filing by failing to incorporate price explicitly into its forecast. The electricity price forecast is a critical component of a company's overall demand forecast. Nantucket's failure to incorporate price explicitly into its current demand forecast is clearly unacceptable and calls into question the reliability of the Company's entire demand forecast. In addition, this serious deficiency is particularly unfortunate in light of the Company's recent substantial rate increase, its recent institution of time-of-use rates for new customers, and its stated intention to pursue additional rate relief in the near future. Clearly, price increases of such a magnitude can be expected to have a significant impact on demand. The Company's failure to consider the likely impact of recent price increases on demand indicates that its base case demand forecast, in fact, may be too high.

The Company's methodology and assumptions for implicitly incorporating price into its demand forecast have numerous weaknesses. First, as Dr. Stutz conceded, there is no rigorous way to translate specific electricity price changes into specific changes in appliance saturations and appliance efficiencies, or vice versa. In effect, with its current methodology, the Company has no means of differentiating between the impact of a five percent price increase and a 500 percent price increase. Moreover, appliance saturation and efficiency levels are affected by a number of factors. In addition to price, they are affected by such factors as consumer tastes and mandated efficiency standards. Second, Nantucket's assumption in its base case that electricity prices will decline relative to alternatives appears unreasonable in light of the aforementioned rate increase and the Company's plans to seek an additional rate increase. Third, the Company's methodology does not permit it to reflect accurately the potential impact on the Company's rates of bringing additional supplies on-line. Fourth, the Company unrealistically assumed that only residential space and water heating penetrations and commercial space heating and air conditioning penetrations were dependent on price and that other appliance penetrations were independent of price.

The Siting Council recognizes that the incorporation of price into end-use models is a somewhat complex task and that appropriate price elasticity data may not be readily available for Nantucket. The Siting Council further recognizes that Nantucket is a small electric company. Nevertheless, even for a small electric company, the Siting Council cannot countenance the failure to account for the important interrelationship between price and demand in its forecast. The Siting Council notes that Taunton Municipal Lighting Plant, another small electric company, has incorporated a price forecast into its demand forecast. Taunton Municipal Lighting Plant, 15 DOMSC 169, 173-177 (1986). In recent years, the only electric company which has failed to incorporate a price forecast into its demand forecast was Fitchburg Gas & Electric Light Company ("Fitchburg"). Fitchburg Gas and Electric Co., 13 DOMSC 85, 95, 102 (1985). In that decision, the Siting Council cited the importance of electricity prices in determining the demand for electricity and strongly criticized Fitchburg for failing to incorporate a price forecast into its demand forecast. Id. at 95, 97.

Accordingly, the Siting Council finds that Nantucket has failed to establish that its electricity price forecasting methodology is appropriate. The Siting Council ORDERS Nantucket in its next forecast filing to incorporate historical and projected electricity prices explicitly into its residential and commercial sales forecasts.

4. Residential Energy Forecast

The record indicates that the residential sector is Nantucket's largest customer sector, accounting for approximately two-thirds of the Company's annual electricity sales in 1990 (Exh. HO-4, p. 1). The record shows that in 1988, the Company had 6,435 residential customers and residential sales of 57,172 MWH (Exhs. HO-D-6). In its base case forecast, the Company projects that residential electricity sales, unadjusted for Company-sponsored C&LM, will increase at a compound annual growth rate of 2.3 percent over the period 1989 to 2008 (Exhs. HO-G-3, NAN-1, pp. 3-16 to 3-17, Chapter 3, Appendix A).[8]

Under the Company's end-use based methodology, total residential energy consumption is calculated as the sum of the estimated annual consumption of 17 residential appliance types (Exh. Nan-1, pp. 3-13, 3-15).[9] The estimated consumption of each residential appliance type is the product of: (1) the number of residential customers; (2) the average number of appliances per customer ("appliance saturation"); and (3) the average annual electricity use per appliance (id., p. 3-13).[10]

A brief explanation of how the Company forecasted each

8/ In addition to a base case forecast, the Company also provided low and high forecasts for the residential sector (Exh. NAN-1, pp. 3-17). These three forecasts differ from one another in one or both of the following respects: (1) projections of the number of residential customers; and (2) the assumed future penetration rates for space heating and water heating. In its low case, the Company projects that residential sales will increase at a compound growth rate of 2.0 percent between 1989 and 2008 (id., Chapter 3, Appendix A). In its high case, the Company projects that residential sales will increase at a compound growth rate of 2.8 percent between 1989 and 2008 (id.).

9/ Nantucket disaggregated its residential forecast into the following 17 appliance types: electric space heaters, electric water heaters, lighting, dishwashers, clothes washers, clothes dryers, electric ranges, microwave ovens, frost free refrigerators, standard refrigerators, frost free freezers, standard freezers, color televisions, black and white televisions, room air conditioners, central air conditioning, and miscellaneous (Exh. NAN-1, p. 3-15).

10/ The Company stated that it calibrated the results of its residential model using a factor of .8544, based on the ratio of actual sales to model-estimated sales for the base year, 1988. This factor was then used to adjust the end-use model estimates for residential sales for each year of the forecast (Exh. HO-RR-4; Tr. 1, pp. 48-51). Dr. Stutz stated that he chose to apply a calibration factor to total residential consumption in Nantucket's case because of the seasonal nature of Nantucket's residential loads, which he asserted introduces inherent uncertainty into the forecast for each end-use (id.).

component of its annual residential energy consumption equation is provided below.

a. Number of Residential Customers

Nantucket's forecast of the number of residential customers was based on forecasts of the number of residential dwellings included in the aforementioned Herr and RKG reports (id., p. 3-14). In Section II.B.2, above, the Siting Council accepted Nantucket's methodologies for forecasting economic and demographic factors.

The Siting Council accepts Nantucket's forecast of the number of residential customers.

b. Number of Appliances per Customer

Nantucket stated that it established the average number of appliances per customer (i.e., appliance saturation levels) for the base year using data from a residential survey completed for the Company by LaCapra Associates in August, 1989 (id., Chapter 2, Appendix B).[11] The Company stated that it derived estimates of the future number of appliances per customer in two ways, depending on the appliance type (id., p. 3-14).

For all appliance types except space heating and water heating, the Company used appliance-specific forecasts of changes in saturation levels taken from the 1987 forecast and supply plan filed with the Siting Council by a neighboring utility, Commonwealth Electric Company ("ComElectric") (id., p. 3-14, Exh. HO-RR-3). Dr. Stutz explained that the Company decided to use ComElectric data because: (1) Nantucket-specific data on appliance saturation trends was not available; and (2) ComElectric was the closest comparable utility (Tr. 1, pp. 76-77).

11/ Nantucket stated that a residential appliance use questionnaire was mailed to over 5,000 customers, and approximately 3,240 of these questionnaires were completed and returned (Exh. NAN-1, p. 2-2). The Company further indicated that it plans to conduct a new appliance use survey in the near future (Tr. 2, p. 25).

For space heating and water heating -- the two largest residential end-uses -- the Company assigned Nantucket-specific projected penetration values which were assumed to remain constant over time (Exh. NAN-1, p. 3-14).[12] The Company stated that it forecasted penetration levels for space heating and water heating in this way because of: (1) the large relative size of these end-uses and their consequent importance to the calculation of load growth; (2) the historically high saturation levels of electric space and water heating on Nantucket relative to other service territories; and (3) the historical volatility of the penetration rates of these appliances on Nantucket (id., pp. 1-10, 3-14; Tr. 1, pp. 53, 59, 60).[13]

The Company further stated that it selected and evaluated "high" and "low" values for future electric space heating and water heating penetration rates (Exh. NAN-1, p. 3-14). The Company stated that in its base case and high case forecasts it assumed an electric space heating penetration level of 71.9 percent and an electric water heating penetration level of 71.1 percent, based on building permit data showing average penetration rates experienced on the Island from 1986 to 1988 (id., pp. 3-14, Chapter 3, Appendix A). The Company further stated that it chose a projected penetration rate of 50 percent for both space and water heating for its low case residential forecast based on the longer-term history of saturation rates for these appliances on Nantucket and "to simulate a significant change from current building practice on the Island" (id., p. 3-14).

12/ Appliance saturation levels represent the market share of the existing stock of a particular appliance type, whereas appliance penetration rates refer to the market share of incremental appliance purchases in a given year.

13/ The record indicates that in 1988, space heating saturation on Nantucket equalled 49.6 percent and water heating saturation equalled 58.1 percent (Exh. NAN-1, p. 3-15). In contrast, in 1987 ComElectric's saturation rates for space heating and water heating equalled 13.9 percent and 26.9 percent, respectively (id., Chapter 3, Appendix A).

However, more recent data provided by the Company indicates that electric space heating and water heating penetration rates have decreased to 35 percent in 1990 (Exh. HO-RR-10). Although the Company stated that this more recent data was not available at the time the Company's demand forecast was prepared, there were indications in the Company's filing that space heating penetration was declining (Exh. NAN-1, Appendix to Chapter 4; Tr. 1, p. 57). Specifically, the Company's filing states that:

> In the last year, the new construction industry on the Island has changed dramatically. Housing starts are down from the mid-80's. What homes are being built are predominantly oil-heated. Electric rates for all customers have risen, and new homes come under a time-of-use rate which can sharply penalize customers who heat with electricity (Exh. NAN-1, Appendix to Chapter 4).

The Company further asserted, however, that this recent data is a short-term aberration and therefore should not be relied on for long-term projections (Company Brief, p. 30). The Company stated that "the possibility that over 50 percent of potential water and space heating markets would be served by alternate fuels is not realistic in view of the Island's overall fuel supply characteristics" (Exh. NAN-1, p. 1-10).

In addition, Dr. Stutz explained that the decision to use high penetration rates for space and water heating in the base case forecast was driven by a desire to create "a reasonable spread" between the low and base cases (Tr. 1, pp. 54-59, 61-62). Dr. Stutz further explained that, because of the Company's decision to use the same economic/demographic scenario for the low and base cases (see Section II.B.2, above), the only way to distinguish between the low and base cases was to assume low projected penetration rates for space and water heating in the low residential case, and to assume high projected penetration rates for space and water heating in the base case (id.).

The Company's residential survey provided a detailed snapshot of appliance use on the Island and serves as an important base year reference point for the model's projections. The Siting Council notes that the response rate for this survey was unusually high, thereby providing a high degree of confidence in its accuracy and in the accuracy of the Company's base year appliance saturation data.

Nantucket did not fully justify its use of ComElectric appliance penetration trends for the 15 appliances. The Siting Council, in previous decisions, has criticized companies for using non-service-territory specific data. 1989 MECo Decision, 18 DOMSC at 319-322; 1988 EUA Decision, 18 DOMSC at 90; 1985 MECo Decision, 12 DOMSC at 221. However, in the instant case, we find that Nantucket's use of ComElectric data for the penetration trends of the 15 appliance types, while less desirable than the use of Nantucket-specific data, is reasonable in light of the Company's small size and the fact that this is the Company's first end-use modelling effort. Moreover, the Company's upcoming residential appliance survey, in combination with the survey completed in 1989, will give Nantucket at least two data sets from which it will be able to analyze Nantucket-specific appliance penetration trends. To the extent that Nantucket continues to rely on ComElectric penetration trend data in the future, however, the Siting Council expects the Company to adequately justify that such data is applicable to the Island.

Nantucket's base case and high case forecasts of appliance penetration trends for electric space heating and water heating, however, rely on the questionable assumption of a 72 percent penetration rate for electric space heating and 71 percent penetration rate for electric water heating over the forecast period. The Company indicated that these penetration rates were based on 1986 to 1988 data, whereas the Company's assumption of a 50 percent penetration rate for space heating and water heating in its low case represents longer-term saturation levels on the Island. However, more recent data indicates that electric space heating and water heating penetration rates have decreased significantly. Given the history of volatility in penetration rates, the Company would have been better served by relying on long-term penetration trend data in its base case rather than data for just three years.

In addition, the Company's use of high penetration rates in its base case forecast appears to have been more the result of the Company's attempt to compensate for its use of the same demographic scenario in both its low case and base case forecasts, rather than by a conviction that the Company's base case penetration rates are the rates most likely to occur over the forecast period. The record in this proceeding demonstrates that the recent rate increase appears to be having at least a short-term impact on electric space and water heating penetration on the Island; given the magnitude of this increase (see Section II.B.3, above), it is possible that penetration rates will be affected significantly in the long-term as well. Accordingly, the Siting Council ORDERS Nantucket in its next forecast filing to reexamine and provide a full explanation of all assumptions made regarding residential appliance saturation levels and forecasted penetration rates in light of both recent experience and long-term historical trends on the Island.

Despite the Company's questionable assumptions regarding space heating and water heating penetration rates, Nantucket's forecast of appliance saturation exhibits significant strengths, especially for a first attempt at end-use modelling. In particular, the high response rate to the residential customer survey and the Company's plans to conduct an additional survey to provide a second data set demonstrate that the Company has collected, and will continue to collect, accurate end-use data. Accordingly, for purposes of this review, the Siting Council accepts Nantucket's forecast of the number of appliances per customer.

c. Electricity Use per Appliance

Nantucket indicated that it used NEPOOL data for estimates of current and projected average annual electricity use per appliance (Exh. NAN-1, p. 3-16). The Company stated that it used NEPOOL data in order to simplify its initial efforts with end-use modelling, and that it expected to develop its own range of appliance average electricity use assumptions in the future (id.). The Company further asserted that the pattern of changes in the NEPOOL data, specifically a downward trend in average electricity use for specific appliances (reflecting efficiency gains) and an upward trend in miscellaneous use, are reasonable given the Company's recent experience on the Island (id., pp. 3-16 to 3-17).

As noted above, the Siting Council has criticized companies for using non-service-territory specific end-use data. However, in the instant case, Nantucket's use of NEPOOL data for average electricity use, while less desirable than the use of Nantucket-specific data, is reasonable in light of the Company's small size and the fact that this is the Company's first end-use modelling effort. Accordingly, the Siting Council accepts Nantucket's forecast of electricity use per appliance.

d. Conclusion

In general, Nantucket has demonstrated marked progress in the manner in which it forecasts residential electricity sales. The Siting Council commends the decision by a small company such as Nantucket to adopt a sophisticated methodology such as end-use modelling to forecast residential electricity demand. The Company's progress also is evidenced by its use of multiple forecast scenarios to evaluate the potential range of uncertainty in its forecast.

The Company's choice of data inputs for its residential model generally is reasonable. However, the Company's residential forecast methodology and assumptions contain some serious flaws at present. Of greatest concern, as noted in Section II.B.2, above, is the Company's failure to incorporate price explicitly into its forecast methodology. (The Siting Council has ordered Nantucket in its next filing to explicitly incorporate price into its residential forecast). An additional concern is the Company's selection of unsupported space heating and water heating penetration rates for its base case forecast.

The Siting Council also notes that the Company provided historical and projected data for the residential sector as a whole, but did not provide separate forecasts for the residential heating and residential non-heating customer classes as required by the Siting Council's regulations at 980 CMR 7.03(7). Accordingly, the Siting Council ORDERS Nantucket in its next forecast to file separate forecasts for (1) the residential heating sector and (2) the residential non-heating sector.

Although the Company has incorporated some questionable assumptions in the application of its residential end-use model, Nantucket has made substantial progress in developing a sophisticated new end-use methodology. The Siting Council has accepted Nantucket's forecasts of the number of residential customers, the number of appliances per customer, and average electricity use per appliance. Accordingly, the Siting Council finds that, for the purposes of this review, Nantucket's forecast of residential energy requirements is reviewable, appropriate, and reliable. The Siting Council notes that in the future, however, we will be unable to make a similar finding unless electricity price is explicitly incorporated into the Company's residential energy forecast.

5. Commercial Energy Forecast

Nantucket stated that the commercial sector accounted for approximately one-third of its annual electricity sales in 1990 (Exh. HO-G-5a, p. 4).[14] In its base case forecast, the Company projects that commercial electricity sales (unadjusted for Company-sponsored C&LM) will increase at a compound annual growth rate of 2.5 percent (id., Exh. NAN-1, pp. 3-3, 3-21,

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14/ The Company estimated that lighting and miscellaneous use represented approximately 38 percent and 34 percent, respectively, of Nantucket's annual commercial sales in 1987 (Exh. HO-RR-2). In that same year, the Company estimated that space heating and air conditioning accounted for 25 percent and 3 percent, respectively, of the Company's commercial sales (id.).

Chapter 3, Appendix A).[15]

In the past, the Company developed its commercial forecast using an econometric model. 1987 Nantucket Decision, 15 DOMSC at 367. In the current filing, Nantucket presented a new end-use-based methodology for forecasting annual electric use by the commercial sector (Exh. NAN-1, p. 3-17). Nantucket indicated that this methodology is similar in many respects to that employed in the Company's residential forecast (see Section II.B.4, above). For example, the Company stated that it used the same economic/demographic scenarios in the forecasts of both residential and commercial sales to ensure that the commercial forecast is consistent with the corresponding residential forecast (id., pp. 3-16, 3-17; Tr. 1, p. 36).

Nantucket stated that its commercial sector model forecasts electricity sales on a seasonal basis by four end-use types and seven business types (i.e., 28 end-use/business combinations) (Exh. NAN-1, p. 3-17).[16]

The Company stated that the estimated energy consumption of each of the 28 end-use/business type combinations is calculated as the product of: (1) the average number of seasonal

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15/ In addition to its base case forecast, the Company stated that it also developed low and high forecasts for the commercial sector (Exh. NAN-1, pp. 3-17, 3-21). These three forecasts differ from one another in one or more of the following respects: (1) forecasts of commercial employment; (2) assumed future penetration rates for space heating and air conditioning; and (3) appliance efficiency levels. In its low case, the Company projects that commercial sales will increase at a compound growth rate of 1.0 percent (id., pp. 3-21, Chapter 3, Appendix A). In its high case, the Company projects that commercial sales will increase at a compound growth rate of 3.1 percent (id.).

16/ Nantucket stated that it considered two seasons, the heating season, which runs from October through April, and the cooling season, which runs from May through September (Exh HO-RR-5). Nantucket further explained that the four end-use types are: electric space heaters, air conditioners, lighting, and miscellaneous (which is the difference between the total commercial electricity use and the sum of the electricity used by the other three end-use types) (Exh. NAN-1, p. 3-18; Tr. 1, pp. 70-71). The Company identified the seven (footnote continued) employees on Nantucket Island; (2) appliance saturation for each end use; and (3) energy intensity per end use[17] (id., p. 3-18). In addition, the Company explained that for space heating and air conditioning end uses, the above product is multiplied by a fourth factor, the long-term seasonal average number of heating degree days (for space heating) or cooling degree days (for air conditioning) on the Island (id., p. 3-19).[18] The Company stated that electricity sales are then aggregated by building type to produce a forecast of total commercial electricity sales by season (id.).[19]

(footnote continued) business types as: construction/agriculture, transportation/public utilities, wholesale trade, retail trade, financial/insurance/real estate, services, and government/other (Exh. NAN-1, p. 3-18). Dr. Stutz stated that Nantucket's selection of business types is taken directly from ComElectric's commercial sector sales forecast and is a common set of business types used in forecasting commercial sector electricity use (Tr. 1, p. 75).

17/ Energy intensity is a measure of efficiency which is expressed in different terms for temperature sensitive load (e.g., space heating and air conditioning) and non-temperature sensitive load (e.g., lighting and miscellaneous). Specifically, the Company stated that energy intensity is measured in kilowatthours ("KWH") per saturated employee per heating or cooling degree day for space heating and air conditioning (Exh. NAN-1, p. 3-19). The Company further explained that energy intensity is measured in KWH per employee for lighting and miscellaneous (id.). The term "saturated employee" refers to the underlying assumption that the percentage of employees occupying electrically heated or cooled space is approximately equal to the saturation of electric space heating or air conditioning, respectively. The Company stated that the use of such data also assumes a stability in square footage per employee over time (Tr. 1, p. 87).

18/ The Company stated that it used 6,017 heating degree days and 254 cooling degree days as the long-term average for the Island (Exh. NAN-1, Chapter 3, Appendix C).

19/ The Company stated that it calibrated the results of its commercial model by multiplying miscellaneous use energy estimates from the uncalibrated model by a normalization factor based on the ratio of actual sales to model-estimated sales for a base year, 1987. This factor was then used to calibrate the end-use model estimates for commercial sales for each year of the forecast (id., p. 3-19). The Company cited two different calibration factors in the record: 1.1952 and 1.0908 (id., p. 3-19, Chapter 3, Appendix B).

A brief discussion of how the Company forecasted each of component of annual commercial energy consumption is provided below.

a. Commercial Employment

The record demonstrates that Nantucket based its current forecasting methodology on the assumption that commercial sector electricity use is a function of commercial employment (Exh. NAN-1, p. 3-7). Nantucket stated that employment was used as the commercial sector driver for three reasons: (1) employment growth generally is proportional to growth in commercial sector building stock; (2) detailed current and historical Nantucket-specific employment data were available; and (3) commercial employment is used as the commercial sector driver in ComElectric's commercial forecast for the Cape Cod/Southeast Massachusetts region, which served as a model for Nantucket's model (id., pp. 3-7, 3-18; Exh. HO-D-11).

Further, the Company indicated that commercial sector employment is used widely in the electric industry as the driver of commercial load forecasts, citing the ComElectric, NEPOOL and EPRI COMMEND models as examples (Exh. HO-D-11). The Company also stated that commercial employment was particularly useful as a driver for a model for Nantucket because it captured the energy impacts of the Island's seasonal employment patterns effectively (id.).[20]

Nantucket stated that its base and low forecasts of commercial sector employment were based on the "Herr Eight" scenario, and its high forecast of commercial sector employment was based on the "Herr No Cap" scenario (Exhs. NAN-1, p. 3-21, HO-RR-1). See Section II.B.2, above, for a description and analysis of the Company's use of this report.

The Company stated that it allocated total employment projections from the Herr report among the aforementioned seven

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20/ The Company stated that in 1987 summer season employment on the Island averaged 4,100, whereas winter season employment averaged 2,300 (Exh. HO-D-11).

business types and among the heating and cooling seasons based on employment trends developed by analyzing Massachusetts Department of Employment Security ("MDES") data for the period 1980 to 1987 (Exh. NAN-1, p. 3-18, Chapter 3, Appendix C). The Company further stated that it was necessary to gather data in this form in order to conform with the ComElectric energy intensity data used in the forecast (id.).

The Company's use of the Herr Report for commercial employment forecasts and MDES data for trends in employment by business type are reasonable.

The Siting Council notes that, in forecasting commercial demand, most larger electric companies incorporate commercial floor space into their forecasting methodologies as an intermediate step in defining the relationship between commercial energy use and commercial sector employment. 1990 MMWEC Decision, 20 DOMSC at 24, 25; 1989 MECo Decision, 18 DOMSC at 310-314; Northeast Utilities, 16 DOMSC 12-15 (1988). Other companies, like Nantucket, postulate a direct relationship between commercial energy use and employment. Eastern Utilities Associates, 18 DOMSC 89-101 (1988); Cambridge Electric Light Company, 12 DOMSC 39 at 59-60 (1985) ("1985 CELCo Decision").

In the instant proceeding, Nantucket's use of commercial employment as the driver of its commercial demand forecast appears to be reasonable in light of the Company's small size. Further, the use of employment as the driver for the commercial model helps to capture seasonal trends in commercial energy use on the Island. However, the Siting Council notes that it is important for electric utilities to examine whether the use of commercial floor space would improve forecast accuracy. Accordingly, the Siting Council ORDERS Nantucket in its next filing to evaluate and report on the potential benefits and difficulties of incorporating commercial floor space into its commercial forecast methodology.

The Siting Council accepts Nantucket's forecast of commercial employment.

b. Appliance Saturation

Nantucket stated that commercial sector saturation data is required only for space heating and air conditioning because lighting and miscellaneous use have a saturation of 100 percent (Exh. NAN-1, p. 3-18). The Company stated that base year saturation data for commercial sector space heating and air conditioning by business type were obtained from a commercial customer survey conducted by LaCapra Associates in December, 1989 (id., Chapter 2, Appendix B, Chapter 3, Appendix C).[21]

The Company further stated that it selected and evaluated "high" and "low" values for future electric space heating and air conditioning penetration rates (id., pp. 1-11, 3-19). The Company stated that in its base case and high case forecasts it assumed a constant electric space heating penetration rate of 62 percent and a constant air conditioning penetration rate of 61 percent, based on the average penetration rates experienced on the Island during the 1986 to 1988 period, as reflected in Company records (id., pp. 3-19 to 3-20, Chapter 3, Appendix C). The Company further stated that for its low case commercial forecast it chose projected penetration rates for space heating and air conditioning equal to the base year saturation rates for those appliances "in order to describe a scenario in which the fraction of new electrically heated and air conditioned commercial buildings moved back toward historical levels reflecting in part higher

21/ Nantucket stated that it received more than 150 responses to its commercial appliance use survey (Exh. NAN-1, p. 2-2). The record indicates that the Company has approximately 1,000 commercial customers (id., p. 4-28).

electricity prices." (id., p. 3-19).[22, 23]

In the past, the Siting Council has criticized the use of end-use surveys with low response rates. 1990 MMWEC Decision, 20 DOMSC at 17. The 15 percent response rate for Nantucket's commercial appliance use survey is substantially below the response rate for the Company's residential appliance use survey. Such a relatively low response rate provides little confidence in the accuracy of the survey, and therefore in the accuracy of a forecast based in part on such survey results. Nantucket should endeavor to improve substantially the response rate for future commercial appliance use surveys.

An additional weakness of Nantucket's forecast of commercial appliance saturation is the breadth of the Company's miscellaneous category, which represents consumption of all commercial end-uses except for space heating, cooling, and lighting, approximately one third of all commercial energy use. In the past, the Siting Council has criticized commercial forecast methodologies which consolidate numerous end-uses into a single large miscellaneous category. 1990 MMWEC Decision, 20 DOMSC at 31; 1989 MECo Decision, 18 DOMSC at 320-321. Disaggregation is a key component of an end-use model's forecasting capability, and the consolidation of numerous end-uses into a large miscellaneous category defeats the purpose of a disaggregated end-use model. Important characteristics of specific end uses easily could be obscured when the end uses are consolidated into a large miscellaneous category.

22/ The record demonstrates that, in 1987, the Company's saturation rates for commercial space heating ranged from 28 percent for service businesses to 45 percent in the retail trade business (Exh. NAN-1, Chapter 3, Appendix C). The record further demonstrates that for commercial air conditioning in 1987, saturation rates ranged generally from zero to 34 percent, but were 83 percent for service businesses (id.).

23/ The data provided by the Company indicates that, in its low demand forecast, the Company actually used penetration rates for space heating that were generally lower than base year saturation rates, and penetration rates for air conditioning that were generally higher than base year saturation rates (Exh. NAN-1, Chapter 3, Appendix C). The record does not indicate the source(s) of the data actually used.

Accordingly, the Siting Council ORDERS Nantucket in its next forecast filing to identify additional commercial end uses to be disaggregated, or to fully justify the present level of commercial end-use disaggregation.

The Siting Council has criticized the Company for failing to incorporate price explicitly into its forecast methodology (see Section II.B.3, above) and for relying on 1986 to 1988 data for its residential base case appliance penetration data (see Section II.B.4, above). Such criticisms apply equally to the Company's commercial sector methodology.

Accordingly, the Siting Council ORDERS Nantucket in its next forecast filing to reexamine and provide a full explanation of all assumptions made regarding commercial appliance saturation levels and forecasted penetration rates in light of both recent experience and long-term historical trends on the Island.

Accordingly, the Siting Council does not accept Nantucket's forecast of commercial appliance saturation.

c. Energy Intensity

Nantucket stated that it relied on the forecast and supply plan ComElectric filed with the Siting Council in 1987 for base year data on energy intensity by appliance and business type because no Nantucket-specific information of this type was available (Exh. NAN-1, p. 3-19, Chapter 3, Appendix C).[24] This data defines the relationship between commercial employment and energy use and thus is a major input into the commercial model (id., p. 3-19). Nantucket stated that ComElectric was the closest comparable company for which it could obtain such data (Tr. 1, p. 76). For its base year, the Company stated that it used ComElectric data for space heating and air conditioning energy intensity values (Exh. NAN-1, p. 3-19, Chapter 3,

24/ The Company stated that ComElectric's commercial forecast for the Cape Cod/Southeast Massachusetts region provides a valuable set of energy intensity parameters that the Company believes are representative of the commercial building stock, climate and other characteristics of the Island (Exhs. Nan-1, pp. 3-7, 3-18, HO-D-11).

Appendix C).[25] For lighting and miscellaneous use, Nantucket stated that it split aggregate ComElectric data into separate components using NEPOOL data for Massachusetts because Nantucket's assumptions regarding forecasted efficiency changes were different for lighting and miscellaneous use (id.; Tr. 1, p. 82).[26]

The Company stated that in its low case demand forecast for the commercial sector, it indirectly considered the potential effects of reduced energy intensities (i.e., future improvements in appliance efficiencies) mandated by the Massachusetts and national appliance efficiency laws and recent changes in the requirements of the Massachusetts building codes by incorporating NEPOOL projections for appliance energy intensity (Exhs. HO-D-2, HO-D-13). However, in its base case and high case forecasts, the Company generally assumed constant energy intensity/appliance efficiency levels (Exh. NAN-1, p. 3-19, Chapter 3, Appendix C).

The Company's witness, Dr. Stutz, stated that he would

25/ In order to determine its base year energy intensity values for lighting and miscellaneous use, the Company used ComElectric energy intensity estimates for several different years, rather than just for the most recent year provided, 1986 (Exhs. HO-RR-3C, NAN-1, Chapter 3, Appendix C). For example, Nantucket chose to use 1980 ComElectric energy intensity data for the transportation/public utilities sector, and 1986 data for the wholesale trade sector (id.). The Company provided no explanation for its selection process. Nantucket appears to have chosen the lowest or second lowest energy intensity value listed in a time series presented in the 1987 ComElectric filing.

26/ Specifically, in its low demand (i.e., high efficiency) case the Company assumed that space heating, air conditioning, and lighting efficiencies would improve but that miscellaneous efficiency would decrease at a rate of 1.0 percent annually. The Company stated that this energy intensity trend data for its low case was based on the most recent NEPOOL projections of appliance efficiencies for Massachusetts (Exhs. HO-D-2, HO-D-13). For its base and high demand forecasts, the Company assumed no change in the efficiencies of space heating, air conditioning and lighting and an annual decrease of 2.6 percent in the efficiency of miscellaneous use (Exh. NAN-1, Chapter 3, Appendix C).

have preferred to include mandated appliance efficiency improvements in the Company's base case forecast but did not do so because: (1) the forecasted energy demand with such improvements included was judged to be too low to be credible; and (2) the commercial forecast results with such improvements diverged from the base case residential forecast results in a manner contrary to experience (Tr. 1, pp. 36-37, 79-80). Dr. Stutz specifically cited mandated lighting efficiency and water heater standards as being excluded from the Company's base case and high case commercial forecasts (id., pp. 37, 78-79).

The Company's failure to incorporate state and federal government mandated appliance efficiency standards and building code improvements into its base case and high case commercial sector forecasts is a serious shortcoming. When efficiency improvements are mandated, there essentially is no doubt about their future implementation. The Siting Council's regulations require that each forecasting methodology must explicitly consider and quantify conservation programs and policies of the Commonwealth, conservation programs and policies of the federal government, and improvements in the efficiencies of new and existing appliances and machinery, including building insulation. 980 CMR 7.09(2). Thus, such standards should be incorporated into all of the Company's commercial forecasts, not just its low case commercial forecast.

If the Company believed that the results of its base case commercial forecast were not credible if mandated appliance efficiency standards were incorporated into that forecast, it should have reexamined its forecast methodology and/or its set of assumptions rather than failing to incorporate the mandated standards. Clearly, a counterintuitive forecast result should be scrutinized carefully. However, it is highly inappropriate for a company to determine judgmentally what is a "reasonable" demand forecast and to adjust its assumptions in order to produce a preconceived forecast result which it deems to be more "reasonable." Nantucket's use of factually incorrect data to produce what it judged to be a "reasonable" or credible forecast undermines the substantial effort and financial resources it has invested to develop a sophisticated commercial forecast model.

In addition, the Siting Council finds that Nantucket did not fully justify its use of ComElectric and NEPOOL data for base year and projected energy intensity. As noted above, the Siting Council has in the past criticized companies for failing to use service territory specific data. Moreover, the Siting Council notes with concern that Nantucket used ComElectric energy intensity estimates for lighting and miscellaneous use for several different years, rather than for a single recent year, and provided no explanation for this inconsistent selection of data. Furthermore, some of the ComElectric energy intensity values selected by Nantucket dated back as far as the early 1980's. The Company's selection of data in this manner raises serious questions regarding the Company's methodology and the applicability of this ComElectric data to Nantucket. These concerns are particularly serious in light of the large size of lighting and miscellaneous use as a percentage of total commercial sector sales.

Accordingly, the Siting Council does not accept Nantucket's forecast of commercial energy intensity.

Further, the Siting Council ORDERS Nantucket in its next filing to fully document and justify its selection of base year and projected energy intensity values for its commercial forecast.

d. Conclusion

Nantucket has demonstrated significant progress in the manner in which it forecasts commercial electricity sales. Nantucket is to be commended for choosing a sophisticated methodology such as end-use modelling to forecast commercial electricity demand. The Company also deserves praise for its use of multiple scenarios to evaluate the potential range of uncertainty in its forecast. Nantucket's progress in this regard is particularly impressive given the Company's small size and limited resources.

Nevertheless, the Company's choice of data and assumptions in several cases undermines the reliability of the

Company's commercial forecast. The Siting Council notes that electric companies are required to submit forecasts based on substantially accurate historical information and reasonable statistical projection methods. G.L. c. 164, sec. 69J.

The most serious shortcomings in Nantucket's commercial forecast are (1) its failure to incorporate mandated appliance efficiency standards and building code improvements into its base case and high case commercial sector forecasts, and (2) the Company's failure to incorporate price explicitly into its forecast methodology.

Furthermore, Nantucket's use of ComElectric energy intensity estimates for several different years, rather than for a single recent year, raises serious questions regarding the applicability of this data to Nantucket. Additional concerns include basing the commercial forecast on an appliance use survey with a low response rate relative to that of its residential survey, the breadth of the Company's miscellaneous appliance category, and the Company's reliance on short term data for its commercial base case appliance penetration rates.

The Siting Council has accepted Nantucket's methodology for forecasting commercial employment but has not accepted Nantucket's methodologies for forecasting commercial appliance saturation and energy intensity. Although the Company has incorporated some questionable assumptions in the application of its commercial end-use model, Nantucket has made substantial progress in developing a sophisticated new end-use methodology.

Accordingly, the Siting Council finds that Nantucket's commercial forecast methodology is reviewable because it contains enough information to allow a full understanding of the methodology. Further, the Siting Council finds that Nantucket's commercial forecast methodology is appropriate, because the methodology is technically suitable to the size and nature of Nantucket. However, the Siting Council finds that the commercial forecast methodology is not reliable because it does not provide a measure of confidence that the data and assumptions used by the Company produce a forecast of what is most likely to occur. Accordingly, the Siting Council finds that Nantucket's forecast of commercial electricity sales is reviewable and appropriate, but not reliable. The Siting Council notes that in the future, however, we will be unable to make a similar finding unless electricity price and mandated efficiency standards are explicitly incorporated into the Company's commercial energy forecast.

6. Streetlighting Forecast

a. Description

The streetlighting sector currently accounts for 0.3 percent of Nantucket's annual sales (Exh. HO-4, p. 1). Sales in this sector declined by 12 percent between 1985 and 1989, while sales in other sectors increased by 42 percent (Exhs. HO-G-5a, HO-D-17).

Nantucket provided base case, low case and high case forecasts for annual sales to the streetlighting sector (Exh. NAN-1, pp. 3-21 to 3-22, Chapter 3, Appendix D). In the base case forecast, the Company assumed that streetlighting sales would remain constant at their 1988 level of 298 MWH through the year 2008 (id., p. 3-22). The Company did not offer any evidence in support of this assumption, although Dr. Stutz suggested that, because streetlighting is a very small load on the Island, it should be modelled using a straightforward methodology (Tr. 1, p. 99).

Nantucket forecasts annual streetlighting sales of 276 MWH and 363 MWH in the year 2008 under the low case and high case scenarios, respectively (Exh. NAN-1, p. 3-21). The Company developed its low case and high case scenarios for projected streetlighting sales by applying linear time series regression analysis to historical sales data (Exh. HO-D-17). The Company stated that the low case forecast, which is derived from ten years of historic streetlighting sales data, is influenced by recent declines in streetlighting sales (Exh. NAN-1, pp. 3-21 to 3-22). The Company stated that the high case forecast, which is derived from 15 years of streetlighting sales data, reflects longer-term moderate growth in the streetlighting sector (id.).

The Company performed a series of statistical tests on these regressions to determine their statistical validity (id., Chapter 3, Appendix D). Dr. Stutz stated that although the results of these statistical analyses were weak, any error in the base case streetlighting forecast would be negligible in terms of the Company's overall demand forecast because of the small size of the streetlighting sector (Tr. 1, p. 101).

b. Analysis

Nantucket failed to provide justification for its base case assumption that streetlighting sales will remain constant through 2008. In several other recent filings, electric companies which are significantly larger than Nantucket also have assumed that their streetlighting sales would remain constant over the forecast period. 1990 MMWEC Decision, 20 DOMSC at 32-33; Massachusetts Electric Company, 18 DOMSC 295, 327-328 (1990) ("1989 MECo Decision"); Boston Edison Company, 18 DOMSC 201, 221 (1989) ("1989 BECo Decision"). In two of these cases, the Siting Council found that the companies' methodologies for forecasting energy requirements for streetlighting were reviewable, reliable and appropriate. See 1989 MECo Decision, 18 DOMSC at 328; 1989 BECo Decision, 18 DOMSC at 221. In the third case, the Siting Council rejected MMWEC's streetlighting forecast methodology because of a lack of sufficient documentation and a failure to account for the significant differences among MMWEC members in this sector. 1990 MMWEC Decision, 20 DOMSC at 36.

In general, the use of high case and low case scenarios is a useful means of bracketing the range of possibilities inherent in long-range forecasts of electricity demand. Nantucket is to be commended for employing high case and low case scenarios in its streetlighting forecast, an approach which much larger companies, such as MMWEC, MECo and BECo, have not employed in their forecasts.

However, Nantucket has failed to document or support its base case assumption that streetlighting sales will remain constant at 1988 levels over the entire forecast period. Further, regression analyses performed by Nantucket yielded statistically weak results for the Company's high case and low case forecasts, raising serious questions regarding the reliability of these forecasts. Nonetheless, given the extremely small size of Nantucket's streetlighting sector, a significant allocation of Company resources to an improved methodology for forecasting streetlighting sales is not warranted at this time.

Accordingly, the Siting Council finds that Nantucket has, for the purposes of this review, established that its streetlighting forecast is reviewable, appropriate and reliable.

7. Conclusions on the Energy Forecast

The Siting Council has accepted Nantucket's forecast of economic and demographic factors. In addition, the Siting Council has found that: (1) Nantucket has failed to establish that its electricity price forecasting methodology is appropriate; (2) Nantucket's forecast of residential energy requirements is reviewable, appropriate, and reliable; (3) Nantucket's forecast of commercial energy requirements is reviewable and appropriate, but not reliable; and (4) Nantucket's forecast of streetlighting energy requirements is reviewable, appropriate, and reliable.

In evaluating Nantucket's energy forecast as a whole, the Siting Council notes that the Company has demonstrated noteworthy advances in its forecasting methodologies. In particular, the Siting Council commends Nantucket for choosing to develop sophisticated end-use models for its residential and commercial sectors. The Siting Council recognizes that end-use modelling may represent a substantial undertaking for a small electric utility such as Nantucket, particularly at the outset when the data requirements of such models are extensive.

In addition, the Siting Council commends Nantucket's use of multiple demand scenarios and the Company's decision to conduct detailed surveys to collect end-use data for the Island. Nevertheless, the Company's data and assumptions in several instances remain seriously flawed. The Siting Council has set forth a number of orders in this case which address these flaws.

Accordingly, on balance, the Siting Council finds that Nantucket's forecast of energy requirements is reviewable, appropriate, and reliable. The Siting Council notes that in the future, however, we will be unable to make a similar finding unless electricity price and mandated efficiency standards are explicitly incorporated into the Company's energy forecast.

C. Peak-Load Forecast

1. Historical Background

Nantucket's peak demand was approximately 18.8 MW in the summer of 1990 and 16.6 MW in the winter of 1990 (Exh. HO-4, p. 1). However, between 1985 and 1989, the Company experienced its peak demand in the winter, and the Company projects that it will be a winter peaking system in the future (id., Exhs. HO-G-5a, p. 4, NAN-1, pp. 3-3 to 3-4). The Company attributed the shift from a summer peak to a winter peak to a rapid increase in the number of electrically heated year-round homes being constructed on the Island and the increased number of property owners and tourists that come to the Island during the winter in recent years (Exhs. NAN-1, pp. 1-1, 3-4, 3-9, HO-D-7).

The Company stated that the decline in winter peak demand in 1990 was the result of several factors, including: (1) unseasonably warm winter weather; (2) the weakening general economic and employment conditions in the region, and a consequent increase in the number of seasonal homes closed up for the winter; (3) "rate shock" from the new electric rate structure; and (4) intensified public awareness of conservation opportunities (Exh. HO-4, pp. 1-2; Tr. 2, pp. 8-9).

The Company stated that, historically, the Company's winter peak has been highly volatile (Exh. NAN-1, p. 3-8). For example, Nantucket's winter peak declined between 1979 and 1983 at an annual rate of 1.5 percent, but increased at an annual rate of 13.6 percent annually between 1983 and 1988 (id.). In 1990, winter peak decreased sharply to 16.6 MW, from 23.3 MW in 1989 and 25.3 MW in 1988 (Exh. HO-4, p. 1). In contrast, the

Company's growth in summer peak has been relatively stable, increasing at an annual rate of 4.2 percent between 1979 and 1983 and 5.6 percent between 1983 and 1988 (Exh. NAN-1, p. 3-8). In 1990, the Company's summer peak declined slightly to 18.8 MW, from 19.7 MW in 1988 and 18.9 MW in 1989 (id.).

2. Description

Nantucket stated that it developed base case, low case and high case forecasts for both summer and winter peak loads in order to address the potential uncertainty associated with such forecasts (Exhs. NAN-1, p. 3-23, HO-D-3). In its base case forecast (unadjusted for Company-sponsored C&LM), the Company projects that winter peak will increase to 33.2 MW in 2000 and 45.7 MW in 2008, a compound annual growth rate of 4.0 percent, and that summer peak will increase to 23.5 MW in 2000 and 25.6 MW in 2008, a compound annual growth rate of 1.3 percent (Exh. NAN-1, p. 3-3, Chapter 3, Appendix A).[27, 28] See Table 1 for the Company's annual forecast of peak load.

The Company explained that both its winter and summer peak load forecasts were based on projected trends in two variables: (1) low case, base case and high case annual sales forecasts; and (2) seasonal load factor (id., Chapter 3, Appendix E; Tr. 1, p. 104).[29]

27/ In its low case, the Company projected a winter peak of 34.7 MW and a summer peak of 22.5 MW in 2008 (Exh. NAN-1, pp. 3-23). In its high case, the Company projected a winter peak of 58.2 MW and a summer peak of 28.6 MW in 2008 (id.).

28/ After adjusting for projected Company-sponsored C&LM, Nantucket in its base case forecasts winter peak demand to increase to 31.8 MW in 2000 and 44.3 MW in 2008, an annual growth rate of 3.8 percent (Exh. NAN-1, Table 1-2, Chapter 3, Appendix A). See Section III.D.2.a.iii, below for a discussion of the Company's C&LM programs.

29/ Load factor is the ratio of electricity sales in a given time period to the product of installed capacity and the number of hours in that time period. Dr. Stutz cited several factors which influence load factor: (1) weather; (2) usage patterns, particularly for second homes; (3) electricity price; and (4) on-Island activities of an intermittent nature, such as construction (Tr. 1, pp. 9, 112-113).

To develop its projected trends in low case, base case and high case annual sales forecasts, the Company indicated that it first aggregated the projections of annual residential, commercial, and streetlighting sales for the low, base, and high cases (Exh. NAN-1, Chapter 3, Appendix E; Tr. 1, pp. 103-104). The Company explained that the aggregate annual low case, base case and high case projections then served as the basis for the corresponding low case, base case and high case summer and winter peak projections (id.). To allocate the projected aggregate annual sales to the historical peak months of January and August, the Company stated that it developed trends in January and August sales as a fraction of annual sales from regression analyses of historical data (Exh. NAN-1, Chapter 3, Appendix E).

To develop its projected trends in seasonal load factor, the Company explained that it performed regression analyses of historical January (winter peak) and August (summer peak) load factors (id.).[30] Nantucket stated that it developed low case, base case and high case projections of its winter load factor (Exh. NAN-1, p. 3-23).

In its low case winter peak forecast, the Company assumed that winter load factor would remain constant throughout the forecast period at its 1988 value of .584 (id., p. 3-22).

In its base case winter peak forecast, the Company assumed that winter load factor would decline rapidly through 1992 and would decline slowly thereafter (id., p. 1-12; Tr. 2, pp. 32-33). The Company stated that the rapidly dropping winter

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30/ Nantucket explained that it performed a series of statistical tests on these regressions to determine their validity (Exhs. HO-D-3, HO-RR-6). Dr. Stutz acknowledged that he was not pleased with the results of these statistical tests but stated that he believed that they correctly pointed toward the underlying trend that winter-season usage is becoming a dominant consideration in the Company's peak (Tr. 1, pp. 123-126). The results of these statistical tests included: (1) R^2 values ranging from .036 to .369; and (2) T-statistics which in all cases had an absolute value of less than 2.0 (Exhs. HO-D-3, HO-RR-6). Dr Stutz concluded that the regressions are reasonable methodology to rely on until a different type of analysis can be developed (Tr. 1, p. 124).

load factor trend was developed by performing a regression analysis on January load factor data for the period 1980 to 1988, and the slowly dropping winter load factor trend was developed by performing a regression analysis on January load factor data for the same period, excluding the data points for 1983 and 1986, which they claimed exaggerated the downward trend in January load factors (Exhs. NAN-1, Chapter 3, Appendices E and G, HO-D-3, HO-D-14).[31]

In its high case winter peak forecast, the Company stated that it assumed that winter load factor would drop rapidly over time, as it has done in recent years (Exh. NAN-1, p. 3-22; Tr. 2, pp. 32-33).

Dr. Stutz stated that a single trend in the value of summer load factor was developed by performing a regression analysis on August load factor data for the period 1980 to 1988 (Exh. HO-RR-6; Tr. 1, pp. 105-107). The results of this analysis indicate that summer load factor is expected to remain fairly stable over time, increasing from .636 in 1990 to .668 in 2010 (Exh. NAN-1, Chapter 3, Appendix E; Tr. 1, pp. 105-107).

Finally, the Company stated that projections for peak load were then derived by dividing projected electricity sales for January and August by the product of the projected load factor for that month and the number of hours in that month (Exhs. NAN-1, Chapter 3, Appendix E, HO-D-3).

Mr. LaCapra explained that he believed that the base case was the most likely scenario because he expected the historical decline in winter load factor to moderate after 1992 for the following reasons: (1) the implementation of the Company's C&LM programs will result in a more than proportional peak load reduction; (2) the rapid growth in electrically heated homes, particularly second homes, is slowing; (3) customers will adjust

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31/ The Company could not explain why the 1983 and 1986 data were significantly different from other historical data (Tr. 1, pp. 115-116). In both of these regression analyses, the Company stated that it used actual rather than weather-normalized data for calculating load factors (Exhs. HO-D-3, HO-D-16; Tr. 1, pp. 118-121).

to recent price changes over time; (4) the long-term historical load factor, while declining, does not exhibit the swings of the last few years; and (5) the slowdown in the local economy will reduce seasonal use (id., p. 1-12; Tr. 2, pp. 32-33).

Mr. LaCapra indicated that he did not expect the decline in the Company's winter load factor to moderate prior to 1993 because: (1) winter load factor continued to decline in 1990; (2) building permit data and the time lag between obtaining building permits and completing construction indicate that electric space heating penetrations will remain high through 1992; and (3) short-term effects of recent price changes are likely to reduce annual sales more than peak sales (Exh. HO-RR-12; Tr. 2, pp. 35-40).

Dr. Stutz acknowledged that Nantucket's current peak forecasting methodology has significant limitations but stated that the present methodology was the best that the Company could employ in the absence of load research (e.g., metering) and computerized billing data necessary to use a more sophisticated methodology (Tr. 1, pp. 23-24). Dr. Stutz further stated that such load research and computerized billing data was not available at the time that the current peak forecast was developed, but that the Company presently is gathering such information and plans to develop a peak forecasting methodology in subsequent demand forecasts that will capture the dynamics of the Company's winter peak (id., pp. 24, 134-135). According to Dr. Stutz, the key to an improved peak forecasting methodology is not disaggregating at the end-use level alone, but rather understanding and capturing the dynamics of the Company's winter peak (id., pp. 108, 134).

3. Analysis

An electric company's forecast of peak load is vitally important because the results of that forecast to a large extent determine the timing and the magnitude of a company's need for new resources. Moreover, Nantucket's peak forecast is particularly important because: (1) the Company is not interconnected with NEPOOL and thus has no ability to make emergency purchases from other utilities in the event of a capacity shortfall; and (2) the timing and size of incremental resource need may have major financial implications for the Company (see Section III.C.2.c.i, below). The Siting Council also recognizes that the strong influence of occupancy trends in seasonal homes on Nantucket and the resultant volatility in peak demand from year to year appears to present significant difficulties in modelling winter peak accurately.

In the past, the Siting Council has approved methodologies which are similar to Nantucket's peak load forecasting methodology in terms of their use of projected load factor as a means of forecasting peak load. 1990 MMWEC Decision, 20 DOMSC at 37-39; 1986 EUA Decision, 14 DOMSC at 71; 1984 EUA Decision, 11 DOMSC at 82; Eastern Utility Associates, 8 DOMSC 219 (1982).[32] However, the Siting Council also has noted the importance of incorporating the underlying factors which contribute to peak load into the peak load forecast. 1990 MMWEC Decision, 20 DOMSC at 37-39; 1989 MECo Decision, 18 DOMSC at 329-335; 1989 BECo Decision, 18 DOMSC at 222-223; 1988 NU Decision, 17 DOMSC at 17.

The Siting Council notes that Nantucket's peak forecasting methodology appropriately specifies a linkage between annual and peak sales. However, the Company's reliance on trends in load factor to translate forecasted annual sales to forecasted peak sales contains an inherent weakness. Load factor is essentially a ratio between peak and annual sales which does not identify the underlying causes which produce that ratio. Thus, by relying on load factor projections rather than forecasts of the underlying factors which affect the ratio between peak and annual sales, the Company is not able to capture the effects of changes in the underlying factors that contribute to peak load. For example, the Company's peak load forecast is not disaggregated into customer classes or end-uses,

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32/ In each of these cases the electric company assumed that projected load factor remained constant over time and equalled current load factor.

nor does it account for major peak load determinants such as weather effects, varying seasonal consumption patterns, and price effects. The Siting Council notes that it is far more reasonable to forecast peak load directly than to derive projected peak load based on simplified assumptions regarding projected load factor.

As noted previously, the use of high and low scenarios is, in general, a useful means of bracketing the range of possibilities inherent in long-range forecasts of electricity demand. In Nantucket's case, the use of high case and low case scenarios for peak load appears to be particularly appropriate in light of the high degree of volatility in peak demand. Given the Company's small size and limited resources, Nantucket is to be commended for employing high case and low case scenarios in its peak load forecast. However, the results of the statistical tests performed by the Company on its January load factor regression analyses clearly indicate that the regressions are statistically weak.

In addition, Nantucket's failure to normalize historical data for weather in its regression analyses is a significant oversight. Because of the difficulty in forecasting long-term weather conditions, a long-term demand forecast must naturally assume that future weather conditions will be "normal," i.e., equal to some long-term average of historical conditions. In order to project demand under normal weather conditions using regression analysis, historical demand data must also be normalized for weather. Nantucket's failure to normalize its historical data for weather appears to have contributed to the poor statistical results of the Company's regression analyses. Accordingly, the Siting Council ORDERS Nantucket in its next filing to normalize historical demand data for weather in projecting peak demand.

Companies are required to file forecasts with the Siting Council that are based on substantially accurate historical information and reasonable statistical projections. G.L. c. 164, sec. 69J. In determining whether a statistical projection method is reasonable, the Siting Council may consider the size of the company, the state of art of forecasting, and the extent to which forecast methodology requirements are met. See 980 CMR 7.02(9)(b)(2).

In Nantucket's case, the Company's base case and high case peak load forecasts are not supported by statistically valid regression analyses. However, in addition to these regression analyses, the Company has provided a detailed and generally reasonable qualitative justification for its selection of load factor trends. Furthermore, the Company's development of low case, base case and high case projections for peak load and load factor trends are significant improvements over other electric company methodologies which assume a single, constant load factor over the forecast period. Moreover, the Company stated that it recognizes the limitations of its existing methodology and presently is collecting information which will allow it to implement a more sophisticated peak forecasting methodology in its next filing.

Accordingly, in consideration of Nantucket's small size and its concrete plans to improve its peak forecasting methodology in the future, the Siting Council finds that, for the purposes of this review, Nantucket's methodology for forecasting peak load is reviewable, appropriate, and reliable. The Siting Council notes, however, that in the future we will be unable to make a similar finding unless the Company progresses beyond plans and actually develops an improved peak load methodology. Accordingly, the Siting Council ORDERS Nantucket in its next forecast filing to develop and present an improved peak load forecasting methodology which incorporates: (1) the results of the Company's ongoing load research and computerized billing research and (2) major underlying factors of peak load such as weather effects, seasonal consumption patterns, and price effects.

D. Previous Demand Forecast Review

In the 1987 Nantucket Decision, the Siting Council approved Nantucket's demand forecast subject to the following conditions:[33]

> 3. That the Company provide and discuss information, including the most up-to-date available data obtained directly from appropriate state or town agencies or travel facility operators, on changes over recent years in year-round resident population; in travel to and from the Island; and, if available, on non-resident visitation, overnight room occupancy or overnight room capacity. The Company also shall provide and discuss any available projections of year-round population or other reasonable determinants of customer change that have been adopted or released for Nantucket Island for one or more forecast years by any state, regional or local agencies since January 1, 1983.
>
> 4. That the Company develop a minimum of two customer forecast scenarios spanning a reasonable range of growth expectations for Nantucket Island. The Company shall also select a forecast that is the most reasonable among the scenarios evaluated by the Company and which is consistent with the Company's criteria for developing a reliable forecast and for any other planning purposes the Company may choose to consider. The Company shall fully describe its rationale for formulating such scenarios and for choosing the customer forecast it uses in its demand forecast from among such scenarios.
>
> 5. The Company explicitly consider the direct incorporation of year-round population as a determinant of demand in all future filings.
>
> 6. That the Company report year-to-year trends in January residential bills and separate out the number of minimum bills issued to R Class customers for the years 1983 to 1986. The Company shall discuss trends in the number and usage patterns of January minimum bill customers, as compared to other January customers, and make available to the Siting Council information on usage levels of January minimum bill customers for the years 1983 to 1986.
>
> 7. That the Company test and as appropriate use sales forecast models based on past and assumed future prices of electricity broken out by major customer class.

33/ The numbers preceding each condition correspond to their order of presentation in the 1987 Nantucket Decision.

In response to Condition 3, Nantucket stated that it has analyzed and incorporated the results of two recent studies of trends in Island demographics in its current demand forecast, the Herr Report and the RKG Report (Exhs. HO-G-4, NAN-1, p. 1-20). As described in greater detail in Section II.B.2, above, these reports include historical information and projections for a variety of demographic indicators, including seasonal and year-round population, employment, dwelling units, tax revenues, tourism, development and land use, and commercial activity (id.). The Company discussed the use of this demographic data in its description of its current demand forecast in the Company's filing and in responses to a number of hearing questions and information requests (Exhs. NAN-1, pp. 3-11 to 3-13, HO-D-1, HO-D-11, HO-RR-1; Tr. 1, pp. 34-37, 43-47, 57-62).

In Section II.B.2, above, the Siting Council found that Nantucket's forecast of economic and demographic factors is appropriate. Accordingly, the Siting Council finds that Nantucket has complied with Condition 3 of the 1987 Nantucket decision.

In response to Condition 4, Nantucket stated that it analyzed three economic/demographic scenarios based on differing projections in the RKG and Herr Reports (Exh. HO-G-4). The Company stated that it used these projections to develop low case, base case and high case forecasts of annual electricity sales for the residential and commercial classes (id.). The Company further explained that low case, base case and high case forecasts also were developed for summer and winter peak and annual streetlighting sales (Exh. NAN-1, pp. 3-21 to 3-24). The Company described its rationale for formulating scenarios and choosing its base case forecast in its filing and in responses to a number of hearing questions and information requests (Exhs. NAN-1, pp. 1-9 to 1-12, 3-12 to 3-13, HO-D-1, HO-D-2, HO-D-12; Tr. 1, pp. 11, 27-28, 31-47, 55-58, 62, 80). Accordingly, the Siting Council finds that Nantucket has complied with Condition 4 of the 1987 Nantucket decision. More detailed descriptions and analyses of the Company's choice and use of scenarios are provided in Sections II.B and II.C, above.

In response to Condition 5, Nantucket stated that it considered year-round as well as summer population by forecasting summer and winter peak separately (Exh. HO-G-4). The Company further stated that its peak load forecast "is a direct result of the Company's efforts to isolate, identify and quantify the dynamic effects of seasonal and year-round customer usage as they impact peak load" (id.; Exh. NAN-1, pp. 3-3 to 3-4). The Company further argued that the peak forecast is a direct function of the sales forecast, which also addresses the impact of seasonal customer use (Company Brief, pp. 18-19).

Although the record demonstrates that the Company has explicitly considered the use of year-round population in its demand forecast, year-round population is not incorporated directly into the Company's current forecast. Rather, the Company stated that projections of the number of residential dwellings and seasonal employment taken from the Herr and RKG reports, together with forecasts of the Company's summer and winter load factor, form the basis for the Company's projections of annual and peak demand growth. See Sections II.B and II.C, above. The Company did, however, attempt to analyze January residential occupancy trends as a means of understanding the impact of year-round population on peak load (Exh. NAN-1, pp. 3-23 to 3-25). The Company concluded that the results of this analysis were not useful, in part due to the Company's inability to distinguish between bills with significant and insignificant January usage prior to January 1989 because of a lack of computerized billing data (id.). The Company stated that its analysis will be refined in the future to take into account both occupancy and usage as additional data becomes available (id., p. 3-24).

The Company's analysis of January residential occupancy trends is a reasonable yardstick for measuring the impact of year-round population on demand. Accordingly, the Siting Council finds that Nantucket has complied with Condition 5 of the 1987 Nantucket decision. See Section II.C, above, for a more detailed discussion and analysis of the Company's peak load forecasting methodology.

In response to Condition 6, Nantucket provided a summary of year-to-year trends in January residential bills (id., Exh. HO-G-4). The Company stated, however, that it is unable to provide historic information on minimum bills prior to 1987, the time at which the Company installed a computerized billing program which provides the ability to perform bill frequency analyses (Exh. HO-G-4; Company Brief, p. 19). The Company did not provide information on the number and usage patterns of January minimum bill customers, but stated that its analysis will incorporate such information in the future as additional data becomes available (Exh. NAN-1, pp. 3-24 to 3-25).

Accordingly, the Siting Council finds that Nantucket complied with the first part of Condition 6, which required a report on year-to-year trends in January residential bills. However, the Company failed to comply with the second and third parts of Condition 6, which required an analysis of the January minimum bill customers.

In response to Condition 7, Nantucket argued that its demand forecast incorporates the effect of electricity price changes through the use of alternative scenarios for electric space and water heating penetrations and end-use efficiencies (Company Brief, pp. 19-20). The Company provided two different scenarios for projected residential space and water heating penetrations and two different scenarios for projected commercial appliance efficiencies (Exh. NAN-1, pp. 3-14 to 3-17, 3-20 to 3-21). However, the record demonstrates that historical, current and projected electricity prices or price elasticities are not included directly in the model (Exh. HO-D-18). The Company's methodology for implicitly incorporating price into its demand forecast is clearly inadequate. The Company's methodology does not, for example, distinguish between electricity price increases of five percent and 500 percent. This is particularly troublesome in light of the large rate increase that the Company has recently instituted (Exhs. HO-G-18a, HO-RR-8; Tr. 2, p. 14). Nantucket's failure to link electricity demand and price in an acceptable manner is a serious deficiency in the Company's forecast methodology that must be corrected in future filings.

Accordingly, the Siting Council finds that Nantucket has failed to comply with Condition 7 of the 1987 Nantucket Decision. See Section II.B.3, above, for a more detailed discussion and analysis of the Company's attempt to include price in its demand forecast.

E. Conclusions on the Demand Forecast

The Siting Council has found that (1) Nantucket's forecast of energy requirements is reviewable, appropriate, and reliable, and (2) Nantucket's forecast of peak load is reviewable, appropriate, and reliable.

The Siting Council also has found that Nantucket has complied with Conditions 3, 4, 5 and the first portion of Condition 6 of the previous Nantucket decision and has failed to comply with the second and third parts of Condition 6 and Condition 7 of the previous Nantucket decision.

In its review of Nantucket's demand forecast, the Siting Council has noted several weaknesses in the Company's methodologies, assumptions and data. The most serious of these weaknesses are: (1) Nantucket's failure to incorporate price explicitly into its demand forecast; (2) Nantucket's failure to incorporate mandated energy efficiency standards into its base case and high case commercial energy forecast; and (3) Nantucket's use of a peak load forecast methodology which is only minimally appropriate and reliable.

Nevertheless, Nantucket has made significant strides in its demand forecast which outweigh the weaknesses noted by the Siting Council. Specifically, despite its small size, the Company has instituted a sophisticated new end-use forecasting methodology. The Company also has incorporated different scenarios into several aspects of its forecast to account for potential uncertainties. Further, Nantucket has acknowledged certain weaknesses in its demand forecast and is taking concrete steps which will allow it to improve its demand forecast significantly in the future, such as gathering additional data for its peak load forecast. Finally, the Siting Council has set forth a number of orders which address the weaknesses in the Company's current demand forecast. The Siting Council has stated that a rejection will be warranted if Nantucket does not address these weaknesses in its next filing.

Accordingly, the Siting Council hereby APPROVES Nantucket's 1990 demand forecast.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate in G.L. c. 164, sec. 69H, to "provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," the Siting Council reviews two dimensions of an electric utility's supply plan: adequacy and cost.[34]

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. 1985 CELCo Decision, 12 DOMSC at 72; Boston Edison Company, 10 DOMSC 203, 245 (1984). The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company, 15 DOMSC 125, 134 (1986) ("1986 CELCo Decision"). To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it to be able to rely upon alternative supplies in the event of certain contingencies. 1987 BECo Decision, 15 DOMSC at 309-322; 1986 CELCo Decision, 15 DOMSC at 134-135, 144-150, 165-166.[35]

34/ Diversity, which in past Siting Council decisions has been discussed separately, now is treated within the discussion of least cost (see Section III.D.2.b, below).

35/ The Siting Council defines the short run as four years. The four year period is measured from the time in a proceeding that (1) the final discovery or record response is submitted, or (2) the final hearing is held, whichever is later. 1989 BECo Decision, 18 DOMSC at 225 n.10, see also 1988 EUA Decision, 18 DOMSC at 106 n.21.

To establish adequacy in the long run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of resource options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate, cost-effective energy and power resources over all forecast years. Generally, a supply plan that meets the least-cost standards set forth below is deemed adequate in the long-run.

The Siting Council next determines whether a supply plan minimizes the cost of power (that is, whether it ensures least-cost supply) subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of facilities. (1987 Nantucket Decision, 15 DOMSC at 384-390). Recognizing that supply planning is a dynamic process carried out under circumstances which make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast (1987 Nantucket Decision, 15 DOMSC at 378-379, 384, 390-391; 1987 BECo Decision, 15 DOMSC at 301, 322-323, 339-348; 1986 CELCo Decision, 15 DOMSC at 133-135; Fitchburg Gas and Electric Light Company, 13 DOMSC 85, 102 (1985)), the Siting Council's review of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. 1987 BECo Decision, 15 DOMSC at 339-349; 1986 CELCo Decision, 15 DOMSC at 136-138.

The Siting Council reviews a company's processes of identifying and evaluating a variety of supply sources. In reviewing a company's resource identification process, the Siting Council analyzes whether that company identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of available resource options. In reviewing a company's resource evaluation process, the Siting Council determines whether that company (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all of its identified resource options. 1989 BECo Decision, 18 DOMSC at 46-76; 1988 EUA Decision, 18 DOMSC at 36-55.

B. Supply Planning Process

1. Introduction

Nantucket stated that it has developed a new supply planning process which is designed to ensure that demand-side and supply-side resources are evaluated on an equal footing (Exh. NAN-1, pp. 1-7, 4-1). The Company stated that the overall goal of its supply planning process is to minimize the Company's annual revenue requirements while maintaining an acceptable level of reliability of service (id., p. 1-4).

The Company indicated that its supply planning process results in a least-cost integrated resource plan (id., pp. 1-5, 4-1). Nantucket defined a least-cost plan as the plan which results in the minimization of total life cycle costs (id., p. 1-5). The Company further stated that the fundamental characteristic of a least-cost plan is the consistent integration and evaluation of three basic planning elements: (1) a load and capacity forecast; (2) a demand-side plan; and (3) a supply-side plan (id.).

In addition, the Company indicated that it has developed a new reliability standard for electricity generation (id., p. 1-4). Specifically, the Company stated that it has adopted a 32 percent reserve margin standard based on maintaining a loss of load probability ("LOLP") of one day in five years (id., p. 1-18). The Company employed this new reliability standard in its analysis of supply plan adequacy (id., pp. 5-16, 5-18). The Siting Council analyzes the appropriateness of this reliability standard in Section III.C.1, below.

2. Description

The Company stated that its supply planning process began with the preparation of a series of energy and peak demand forecasts (id., p. 5-14). Nantucket explained that it chose to use its base case energy and peak forecast as the reference point for future supply plans because the Company believes that the base case forecast is the scenario which is most likely to occur (id., pp. 5-14, 5-15). For a detailed discussion of the Company's demand forecasts, see Sections II.B and II.C, above.

Nantucket indicated that the next step in its supply planning process was the development of estimates of energy and peak savings from Company-sponsored C&LM programs over the forecast period (id., p. 5-15). The Company stated that these estimates were based on evaluations of C&LM program designs for the residential and commercial sectors developed in Phase II of the Collaborative Process (id.).[36] Nantucket stated that it screened C&LM technologies for cost-effectiveness based on a comparison with the Company's avoided costs for a supply plan unadjusted for the effects of the Company's new C&LM activities (id., p. 4-2). The Company stated that in the current filing it used updated avoided costs based on the Company's "Second Solicitation Request for Proposals" filed in May, 1990 with the Massachusetts Department of Public Utilities ("MDPU") (id., pp. 4-3, 4-4). Nantucket stated that it then subtracted these estimates of energy and peak savings from Company-sponsored C&LM programs from the Company's base case energy and peak forecasts in order to produce C&LM-adjusted forecasts of energy and peak requirements (id.).

Nantucket stated that the next step in its supply planning process was to develop a set of projected seasonal operating conditions over the forecast period for its existing generation mix, taking into account planned maintenance schedules, equivalent forced outage rates, unit dispatch schedules and planned unit retirements (id., pp. 5-16 to 5-17).

36/ The Company explained that the Collaborative Process is a cooperative venture between electric utilities in Massachusetts, the Conservation Law Foundation and other parties, focusing on the design of utility-sponsored C&LM programs (Exh. HO-S-27). The Company explained that broad guidelines for generic C&LM programs were established in Phase I of the Collaborative Process whereas Phase II involved the design of C&LM programs specific to each participating utility (id.).

Nantucket stated that it compared projected unit operating conditions with projected load duration curves for each season of each year of the forecast period based on the C&LM-adjusted forecast (id., p. 5-18). The Company stated that for each unit operating condition and each potential single unit or multiple unit failure, the probability of dropping load was calculated and multiplied by the projected number of hours during which this operating condition prevailed and by the average duration of such a generation outage (id.). Nantucket stated that the expected loss of load hours were then summed across all operating conditions and failure conditions for the summer and winter seasons (id.). Finally, the loss of load hours for the two seasons were combined and converted into loss of load days per five years (id.). The Company explained that new capacity is required when the projected loss of load hours exceeds the Company's proposed reliability standard of a LOLP of one day in five years (id.).

The Company stated that the final step in its supply planning process was to screen and evaluate a full range of incremental supply sources and strategies related to the location of supply sources (id., p. 5-23). The record indicates that Nantucket employed a two-phase process for screening and evaluating alternative supply sources (id., pp. 5-24 to 5-27).

The record shows that in the first phase of this process, the Company screened out supply sources which it considered to be technically, economically or environmentally infeasible for use on the Island (id., pp. 5-24 to 5-26). Nantucket stated that in the second phase of this process, it evaluated each of the remaining supply sources using life cycle cost analyses (id., p. 5-27). The Company stated that, as a part of this analysis, it estimated the net present value of the total revenue requirements of a series of alternative supply plans, each of which differed only in the incremental supply source(s) under consideration (id., p. 5-33). Nantucket indicated that its preferred supply source was that source which was included in the supply plan which minimized the net present value of the Company's total revenue requirements (id.). The Company stated, however, that in making its ultimate selection of an incremental supply source it examines detailed manufacturer's technical specifications and performs more detailed engineering analysis (id., p. 5-34). The Company stated that its preferred supply source potentially could be disqualified if that source is found to be inadequate during such a detailed investigation (id., p. 5-34). For a more detailed discussion and analysis of Nantucket's resource identification and evaluation process, see Section III.D, below.

C. Adequacy of the Supply Plan

1. Reliability Standard

In its analysis of the adequacy of an electric company's supply plan, the Siting Council typically compares the company's projected resource capability (i.e., the total capacity of its supplies) with its peak load capability responsibility as required by NEPOOL. See e.g., 1990 MMWEC Decision, 20 DOMSC at 47-48. However, because Nantucket is not interconnected with NEPOOL, the Company is not required to maintain a NEPOOL-determined peak load capability responsibility. Consequently, in place of a peak load capability responsibility, Nantucket has proposed a specific reliability standard for its system. A description of the Company's process for establishing this reliability standard and the Siting Council's analysis of the acceptability of this standard for the Nantucket system are provided below.

a. Description

Nantucket stated that the first step in establishing an overall system supply plan is a determination of an adequate level of system reliability (Exh. NAN-1, p. 5-7). The Company asserted that there is a direct tradeoff between cost and reliability, and therefore that a reliability standard must be set which properly balances the price that a customer pays for electricity with the reliability of service that the customer receives (id.; Tr. 2, p. 84).

Nantucket stated that, as part of its current filing, it developed a new reliability standard for its generation system based on the use of LOLP as a reliability criterion (Exh. NAN-1, p. 1-4).[37] Nantucket asserted that LOLP is an appropriate reliability criterion for the Company since, using such a criterion, a high reliability of service can be established without the need to (1) maintain excessively high reserve margins, or (2) operate the Company's generators in a technically inadvisable manner (id., pp. 5-6, 5-8).[38] The Company further stated that most power pools in the United States use this criterion (id.). The Company also indicated that LOLP can be easily converted to a reserve margin standard (id.).

37/ The Company stated that it considered the use of four possible reliability criteria which are commonly used in the electric industry to quantify the amount of installed capacity required by a system: (1) single contingency; (2) double contingency; (3) LOLP; and (4) percent reserve margin (Exh. NAN-1, p. 5-4). The Company stated that the single contingency criterion requires that installed capacity be sufficient to maintain service at the time of system peak with the Company's largest unit out of service, and that the double contingency criterion requires that installed capacity be sufficient to maintain service with the loss of the largest unit at a time when another unit is out of service (Exh. NAN-1, pp. 5-4, 5-5). The Company further stated that the LOLP criterion measures the probability of having insufficient generating capacity to meet load requirements throughout a given time period, and that the percent reserve criterion establishes a fixed percent of annual peak as the installed capacity that must be maintained in reserve (id., p. 5-5).

38/ Nantucket asserted that single contingency and multiple contingency criteria were inappropriate for an isolated system such as Nantucket's because the Company has no opportunity to enhance reliability through transmission connections with other electric companies and consequently the reserve requirements for such criteria would be excessive (Exh. NAN-1, pp. 5-6, 5-8).

In addition, the Company stated that a single contingency criterion frequently would force the Company to operate its diesel engines in spinning reserve at thermally inefficient and mechanically inadvisable levels (id.). Nantucket estimated that it would require spinning reserves of 53 percent to meet the reserve requirements of a single contingency criterion during average load periods (id., p. 5-8). The Company stated that this spinning reserve margin is three times that typical for interconnected systems (id.).

Specifically, Nantucket stated that it selected a reliability standard equal to a LOLP of one day in five years, which the Company stated is approximately equal to a reserve margin of 32 percent (Exh. NAN-1 pp. 1-18, 5-7, 5-18, 5-19; Tr. 2, pp. 79, 99-101). The Company stated that this standard is a somewhat lower level of reliability then the NEPOOL LOLP standard of one day in 10 years (Exh. NAN-1, p. 5-7). The Company asserted that a LOLP of one day in five years "lies within typical industry values" and "is an attainable, economically appropriate and manageable standard" for Nantucket (id.). Nantucket stated that, as an isolated system, it was unable to realize the economies of interconnected systems such as NEPOOL, which are able to take advantage of diversity and remote generation to achieve higher levels of reliability without the burden of excessively high reserve margins (id.).

The Company further stated that the additional generation capacity required to attain a higher reliability level than one day in five years would have a significant financial impact on the Company and a significant rate impact on its customers (id.). Specifically, the Company estimated that a LOLP standard of one day in 10 years for Nantucket would result in increased costs of approximately $11.2 million on a net present value basis over the forecast period (Exh. HO-S-18). The Company stated that this would result in an increase of 11 percent or more in customer rates (id.). The Company stated that it strongly believes that a slight reduction in loss of load hours in exchange for a large rate increase would not be consistent with the wishes of the Company's ratepayers (Exh. NAN-1, p. 5-7). Finally, Nantucket stated that its present ratios of capacity to both peak and average load are significantly higher than those typical for pool-interconnected utilities (id., p. 5-8)

b. Analysis

Nantucket has demonstrated that it evaluated a number of possible types of reliability criteria and chose LOLP and reserve margin as the most appropriate criteria for the

Company's system. In addition, the Company demonstrated that a LOLP of one day in five years represents a reasonable level of reliability for the Nantucket system in light of the tradeoff between cost and reliability and the unique problems of an isolated electric system which is unable to take advantage of the economies of diversity and remote generation available to systems which are interconnected with a regional power pool.

Accordingly, the Siting Council finds that Nantucket's generation reliability standard of a LOLP of one day in five years, equivalent to a reserve margin of 32 percent, is acceptable.

2. Adequacy of the Supply Plan in the Short Run

a. Definition of the Short Run

As noted in Section III.A above, the Siting Council has defined the short run for all electric companies as four years from the date of the final hearing or from the date of the response to the final record request, whichever is later. The final Nantucket hearing was completed on October 23, 1990, and the final record request response was received by the Siting Council on January 25, 1991. Therefore, in this proceeding, the short run extends from the winter of 1990-1991 through the summer of 1994.

b. Base Case Supply Plan

Nantucket projects a short-run surplus over the forecast period, with reserve margins ranging from 36 percent to 48 percent (Exh. HO-S-34). However, the record indicates that the short-run supply data provided by the Company is incorrect in three respects. First, the Company assumed in its base case supply plan that 0.7 MW of customer self-generation will be available throughout the forecast period (id.). However, the Company stated that while this generation currently is in place, it cannot be counted on for firm supply until 1994 (Exh. NAN-1,

p. 5-13).[39] Second, while the Company's data indicates that 1991 C&LM-adjusted winter peak demand will be 22 MW, the Company's witness testified that the Company's projection actually is 22.5 MW (Tr. 2, p. 43). Finally, although the Company included Unit 3, a 34-year old 1.25 MW diesel generator, in its base case supply plan for all years of the forecast period, the record indicates that Unit 3 shifted on its foundation in January 1990, and that continued operation of the unit would result in damage to its crank shaft (Exh. HO-4, p. 3). Nantucket concluded that repair of Unit 3 could be financially justified if there is a need for the unit's capacity, but that such a need does not exist presently (id.). Therefore, Nantucket indicated that Unit 3 has been mothballed indefinitely and currently is not on the Company's dispatch schedule (id.).

Based on the aforementioned adjustments to the figures provided by the Company, Nantucket's expected reserve margin is in excess of its 32 percent standard in 1991 and 1993, but slightly below this standard in 1992 and 1994 (see Table 3). In 1992, the Company's expected reserve margin is 30.2 percent and in 1994, the Company's expected reserve margin is 30.1 percent. The Siting Council notes that, while the Company's projections demonstrate reserve margin deficits in 1992 and 1994, these deficits are very small -- only 0.4 MW in both cases. In addition, as discussed in Section II.B.3.b, above, the Company's

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39/ The Company stated that there are 28 potential self-generators on the Island with a total installed capacity of 1.618 MW (Exh. NAN-1, pp. 5-11, 5-12). The Company stated, however, that none of these customer generators presently are connected in parallel to the Company's distribution system, and therefore, none have the capability to displace any use beyond their own peak use (id., p. 5-12). Thus, the Company stated that the potential maximum peak displacement from these units is 1.223 MW in the summer and .89 MW in the winter (id.). The Company stated that after factoring in estimates of reliability and coincidence factors, it projects a total of .917 MW in the summer and .72 MW in the winter to be available for peak shaving purposes (id., p. 5-13). The Company further stated that it will implement programs to place a target level of .72 MW of winter capacity self-generation under contract by 1994 and that such capacity will not be relied upon prior to that time (id.).

base case load forecast may be too high in the short term, which diminishes the likelihood that supplies actually will fall below the Company's reserve margin standard in the short run. Accordingly, in light of the small size of the projected reserve margin deficiencies, and the potentially high base case load forecast, the Siting Council finds that, on balance, Nantucket has established that its base case supply plan is adequate to meet projected base case requirements in the short run.

In making this finding, however, the Siting Council notes two concerns with the Company's base case supply plan.

First, the Company has experienced reliability problems with its existing generation units (Exh. HO-4, p. 3). Specifically, two of these units have failed in the past two years and remain off-line (id.). Two additional small units are 29 and 43 years old, respectively, and the Company's larger baseload units are 14, 19 and 23 years old, respectively (Exh. NAN-1, Table 5-1). Moreover, the Company stated that these three larger baseload units currently carry most of Nantucket's electric load, each operating approximately 7,000 to 8,000 hours annually (Exh. HO-4, pp. 4, 6). The Company stated that such heavy dependence on just three units is not optimal (id., p. 4). The Company further noted that an additional baseload unit would remove some of the load burden on these units and help extend their operational lives, but that such an option is not feasible at present given the Company's present financial difficulties (id.). See Section III.C.2.c.i, below, for a discussion of the Company's present financial situation.

Due to the Company's reliance on these units, it is particularly important that the Company adequately maintain these existing units and continuously evaluate whether the replacement of the oldest units prior to scheduled retirement dates is warranted. Accordingly, the Siting Council ORDERS Nantucket in its next filing to (1) estimate the impact of potential resource additions on the reliability and life expectancy of the Company's existing generators, and (2) document its consideration of this impact in its determination of the appropriate timing of incremental resource additions.

Second, the Siting Council is very concerned that the Company failed to directly notify the Siting Council during the course of the current proceeding that Unit 3 has been mothballed. The Siting Council only learned of this information after the conclusion of hearings in this proceeding, although the unit was mothballed several months prior to the hearing dates. It is a utility's responsibility to provide the Siting Council with complete, accurate and up-to-date information. The Siting Council expects that Nantucket will not fail in this responsibility in the future.

c. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must establish that it can meet its forecasted needs under a reasonable range of contingencies. Therefore, to evaluate the adequacy of Nantucket's short-run supply plan, the Siting Council analyzes Nantucket's base case supply plan with respect to the effects of (1) high peak load growth, and (2) inability to repermit Units 10 and 11 as incremental units.

i. High Peak Load Growth Contingency

In its short-run high load growth scenario, Nantucket projects that its winter peak load, adjusted for company-sponsored C&LM, will increase from 21.3 MW in 1990 to 25.2 MW in 1994 (Exh. NAN-1, Chapter 3, Appendix A, Table 1-2). Under high winter peak load growth conditions, with all resources in its base case supply plan remaining available, Nantucket's reserve margin would range from 24.2 to 32.5 percent in the short term (see Table 4). As such, the Company's base case supply plan would fail to attain the Company's reserve margin standard in 1992, 1993 and 1994 under the Company's high peak load growth scenario. At maximum, the Company's peak load deficiency would equal 1.96 MW in 1994 under this scenario.

In the event of a high-load-growth-related resource deficiency, Nantucket stated that its action plan would consist of either (1) renting one or more trailer-mounted diesel generators, or (2) accelerating the purchase of the Company's next planned supply addition (id., pp. 5-37, 5-38; Exh. HO-S-35).

With regard to the rental of trailer-mounted diesel engines, Nantucket stated that this has been the Company's operating policy in the past and has been implemented without difficulty (id.). Nantucket further stated that vendors have informed the Company that they could deliver three to four 1-MW emergency diesels within seven to ten days (Exh. HO-S-35). The Company stated that larger diesels (2.5 MW to 10 MW) also are available, but may require a longer delivery time and rental of a transformer (id.).

With regard to accelerating the purchase of the Company's next supply addition, Nantucket stated that it could accelerate its acquisition of a planned new 5.7 MW diesel engine, which is scheduled to be operational in March, 1995, by one year if necessary (Exhs. NAN-1, pp. 5-33 to 5-35, HO-S-35). See Section III.D, below, for a further description and analysis of this planned supply addition.

However, the record indicates that the Company may have difficulties in financing the acquisition of a new supply source. The Company stated that it has experienced financial losses and negative cash flows for the past several years, but projects modest earnings and cash flow improvements in the future under a new five-year Financial Plan (Exh. HO-G-16). The Company further stated that "even with the austerity measures contained in the Financial Plan, the Company is simply unable to generate sufficient cash to reduce its outstanding debt sufficiently to enable it to finance a new generator in the 1994-1995 timeframe. Thus, the Company will need to obtain additional revenue if such financing is to be obtained." Id. The Company stated that it has requested the MDPU to approve issuance of tax exempt bonds, that it plans to file for additional rate relief with the MDPU in the near future, and that it is exploring several other options to improve its financial position (id., Exh. HO-S-36; Tr. 2, pp. 124-127).

The Company further stated that an additional 1.895 MW could be obtained on a limited basis because the Company's diesel generators may be run at 10 percent over their rated capacity for up to two hours in any 24-hour period (Exh. NAN-1, p. 5-10). Finally, the record indicates that the Company could bring Unit 3 back on line if necessary to meet higher than anticipated growth (Exh. HO-4, p. 3).

Nantucket has demonstrated that it has the ability to implement its first action plan -- renting trailer-mounted diesel generators -- in a timely manner under the contingency of higher than expected load growth. In addition, the Company has established that implementation of its first action plan would be sufficient to meet potential resource deficiencies in 1992, 1993 and 1994 in the event of higher than anticipated load growth. However, due to the serious financial difficulties currently experienced by the Company, Nantucket has not been able to demonstrate that it would be able to implement its second action plan -- accelerating the purchase of its next planned supply addition -- in a timely manner. Accordingly, the Siting Council finds that Nantucket has established that it has an action plan to meet potential resource deficiencies in 1992, 1993 and 1994 in the event of higher than anticipated peak growth.

ii. Contingency of Inability to Repermit Units 10 and 11 as Incremental Supply Sources

The Siting Council examines the adequacy of the Company's supply plan under the contingency that Units 10 and 11 are not repermitted as incremental supply sources, but instead are allowed to continue to operate as backup units under existing

DEP permits.[40] Under this contingency, with all other resources in its base case supply plan remaining available, Nantucket's reserve margin would range from 29.1 to 34.9 percent in the short run (see Table 4). The Company's base case supply plan would fail to attain the Company's reserve margin standard in 1992, 1993 and 1994 under this scenario. At maximum, the Company's peak load deficiency would equal 0.67 MW in 1992 under this scenario.

In the event of such a deficiency, Nantucket stated that its action plan would consist of renting one or more trailer-mounted diesel generators (id., pp. 5-37, 5-38; Exh. HO-S-35). In addition, the Company stated that it could accelerate plans to procure an incremental supply source if necessary (id.). Finally, the record indicates that the Company also could bring Unit 3 back on line if necessary (Exh. HO-4, p. 3).

40/ Nantucket stated that it currently is seeking DEP approval to operate Units 10 and 11 (1.25 MW each) as incremental units (Exh. NAN-1, pp. 5-19 to 5-21). The Company stated that, at present, these units are permitted to operate only as replacement capacity and are subject to an annual operating limit of 2,650 hours (id.). The record indicates that the current air quality permits for these units have been extended by DEP several times in the past, most recently in December 1990, and are now permitted until July 1, 1991 (Exh. HO-S-31). Nantucket stated that it does not anticipate any difficulties in repermitting these units because the Company is not seeking to increase the annual operating limit of these units, but rather is seeking to remove operational constraints which limit their use to periods when other generators are experiencing outages (Exh. HO-S-15). However, the Company stated that DEP has not yet made a final determination regarding the Company's request for repermitting these units for incremental use rather than for replacement use (Exh. HO-S-31).

The record indicates that under the existing DEP permit, Nantucket can operate either Unit 10 or Unit 11 in place of Unit 2, a 39 year old 1 MW diesel, which the Company stated is currently in a state of "mechanical disarray" (Tr. 2, pp. 91-92). The Company stated that in the event that Units 10 and 11 are restricted to backup use, the Company would defer the official retirement of Unit 2 for up to three years (Exh. HO-S-32). Nantucket stated that, to the extent that Unit 2 is inoperable but not officially retired, the existing DEP permit would allow either Unit 10 or Unit 11 to serve as replacement capacity for Unit 2 (id.).

Nantucket has demonstrated that it has the ability to implement its action plan relating to the rental of trailer-mounted diesel generators in a timely manner under the contingency of the Company being unable to repermit Units 10 and 11 as incremental supply sources. Additionally, the Company has demonstrated that it implementation of its action plan would be sufficient to meet potential resource deficiencies in 1992, 1993 and 1994 under this contingency. Accordingly, the Siting Council finds that Nantucket has established that it has an action plan to meet potential resource deficiencies in 1992, 1993 and 1994 in the event that the Company is unable to secure DEP approval to repermit Units 10 and 11 as incremental units.

The evidence provided by the Company indicates that DEP is likely to repermit Units 10 and 11 for incremental generation or renew the existing permits for Units 10 and 11 as backup supply sources. However, since the existing DEP permits for these facilities are due to expire on July 1, 1991, there is some possibility that DEP will not repermit these units nor renew the existing permits for these units. While the likelihood that DEP will not repermit or extend the existing permits of Units 10 and 11 may be small, if Nantucket fails to obtain new permits or permit renewals, the consequences are potentially severe. Accordingly, the Siting Council ORDERS Nantucket to provide, by July 8, 1991 (1) an update of the status of the air permits for Units 10 and 11, and (2) a copy of any new permit or permit extension for Units 10 and 11 received by the Company from DEP.

iii. Conclusions on the Short-Run Contingency Analysis

The Siting Council has found that Nantucket has established that it has (1) an action plan to meet potential resource deficiencies in 1992, 1993 and 1994 in the event of the contingency of high peak growth, and (2) an action plan to meet potential resource deficiencies in 1992, 1993 and 1994 in the event of the contingency that Units 10 and 11 are not repermitted as incremental units.

Accordingly, the Siting Council finds that Nantucket has established that its supply plan is adequate to meet its system peak load and reserve requirements in the short run under a reasonable range of contingencies.

3. Adequacy of the Supply Plan in the Long Run

Nantucket's long-run planning period is the remaining forecast horizon beyond the short run, extending from the winter of 1994-95 through the summer of 1999. Nantucket's base case supply plan would satisfy its projected peak capacity and reserve requirements through the winter of 1999-2000.

As previously discussed in Section III.A, above, the Siting Council requires an electric company to establish adequacy in the long run by demonstrating that its planning process can identify and fully evaluate a reasonable range of resource options. As indicated in Section III.D, below, Nantucket has established that it identified and fully evaluated a reasonable range of resource options. Accordingly, the Siting Council finds that Nantucket has established that its supply planning process ensures adequate resources to meet requirements in the long run.

In making this finding, the Siting Council notes that, as indicated in Section III.C.2.c.i, above, Nantucket presently is experiencing serious financial difficulties which potentially may inhibit the Company's ability to purchase incremental supply sources. Nantucket's present planned supply additions all are scheduled to come on-line in the long-run planning period. To the extent that these supply additions are identified as being required in the short run in the Company's next filing, the Siting Council expects Nantucket to fully document its ability to finance such supply additions.

Accordingly, the Siting Council ORDERS Nantucket in its next filing to provide detailed information on the Company's plans and ability to secure financing for resource additions planned for the short run.

4. Conclusions on Adequacy of the Supply Plan

The Siting Council has found that Nantucket has established that (1) its base case supply plan is adequate to meet requirements in the short run; (2) its supply plan is adequate to meet its capacity and reserve requirements in the short run under a reasonable range of contingencies; and (3) its supply planning process ensures adequate resources to meet requirements in the long run.

Accordingly, the Siting Council finds that Nantucket has established that its supply plan ensures adequate resources to meet projected requirements.

D. Least-Cost Supply

In this section, the Siting Council reviews Nantucket's processes for identifying and fully evaluating resource options.

1. Identification of Resource Options

Nantucket identified both generation and C&LM options for evaluation. The Siting Council focuses its review on whether Nantucket identified a reasonable range of resource options by (1) compiling a comprehensive array of available resource options, and (2) developing and applying appropriate criteria for screening its array of resource options.

a. Available Resource Options

In order to determine whether Nantucket compiled a comprehensive array of available resource options, the Siting Council must determine whether the Company compiled adequate sets of available resource options for each type of resource identified during the current proceeding.

i. Types of Resource Sets

The record indicates that Nantucket identified three types of resource sets for consideration in its supply planning process: (1) new Nantucket-owned supply sources; (2) purchases from non-utility supply sources; and (3) new Nantucket-sponsored C&LM programs (Exh. NAN-1, pp. 5-22 to 5-23; Tr. 2, pp. 144-148, 151-153). Nantucket stated that its supply options are restricted because of the Island's isolation, small size, limited port facilities and limited availability of land (Exh. NAN-1, p. 5-26). Moreover, the Company explained that it is not interconnected with NEPOOL, and thus cannot purchase power from other utilities (id., p. 1-1).

Nantucket's three types of resource sets represent a reasonable spectrum of resource options available to the Company in light of the size and isolation of the Nantucket system. Accordingly, the Siting Council finds that Nantucket has identified a reasonable range of resource sets.

ii. Compilation of Resource Sets

Nantucket stated that it compiled information on a full spectrum of potential types of Company-owned supply sources (Exh. NAN-1, p. 5-23). Specifically, the Company stated that it considered the following supply sources: (1) coal-fired plants; (2) propane-fired plants; (3) natural gas-fired plants with gas supplied through a pipeline from the mainland; (4) oil-fired plants located offshore; (5) wind turbines; (6) simple-cycle combustion turbines; (7) combined-cycle combustion turbines; (8) baseload simple-cycle diesel engines; (9) baseload combined-cycle diesel engines; and (10) connection to the mainland by underwater electric cable (id.).[41]

In the past, the Siting Council has found that an adequate set of company-owned generation resources included a wide range of capacity factors, size increments, fuel types, and technologies. 1990 MMWEC Decision, 20 DOMSC at 64; 1989 BECo

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41/ The Company stated that it also evaluated several options for the location of existing and new generating facilities, including: (1) capacity expansion at the existing downtown site using the existing foundations of generators which are planned to be retired; (2) relocation of the downtown plant either to the Madaket Road site or to the airport site; (3) construction of a new building to house generators adjacent to the existing downtown site; and (4) location of new generation facilities at a new site (Exhs. NAN-1, p. 5-23, HO-G-1h1).

Decision, 18 DOMSC at 257-258. The Siting Council recognizes that there are practical limitations to the size and location of potential generating facilities on the Island. Given these limitations, Nantucket has compiled a resource set for Company-owned supply sources that represents a reasonable range of technologies, fuel types, plant sizes and locations. Accordingly, the Siting Council finds that Nantucket has compiled an adequate resource set of new Company-owned supply sources.

With regard to potential purchases from non-utility supply sources, Nantucket currently is in the process of instituting a second request for proposals ("RFP") solicitation process ("RFP process") to purchase power from qualifying facilities ("QFs") and independent power producers ("IPPs") (Exhs. NAN-1, pp. 5-11 to 5-13, HO-RR-11; Tr. 2, pp. 144-148, 150-153).[42] The Company's RFP process currently is being reviewed by the MDPU (Exhs. HO-G-1c, HO-G-1d, HO-RR-11). The Company stated that the potential for QFs is limited because there is virtually no steam-load requirement on the Island, and that the potential for IPPs appears to be limited since any such project would face the same physical and geographic constraints as the Company (Tr. 2, p. 151). The Company indicated that it has held discussions with potential private power developers, but that the results of such discussions have not been promising (id., pp. 151-153). In addition, the Company stated that while it currently purchases power from a few small wind turbines, there is limited potential for additional resources of this type (Exh. NAN-1, p. 5-25; Tr. 2, p. 153).

Nantucket has developed a methodology which will allow it to compile a resource set for purchases from non-utility supply sources once the Company's current RFP filing is issued. In previous decisions, the Siting Council has found that a formal

42/ In addition, the Company stated that it has identified 28 potential self-generators on the Island with a total installed capacity of 1.618 MW (Exh. NAN-1, pp. 5-11, 5-12). See footnote 39, above, for additional information on these self-generators.

RFP process subject to approval by the MDPU constitutes an appropriate methodology for compiling a set of available QF purchases. 1989 BECo Decision, 18 DOMSC at 258; 1988 EUA Decision, 18 DOMSC at 115. Similarly, we find here that the RFP process constitutes an appropriate means of compiling a resource set of QF/IPP purchases. Although the Siting Council recognizes that there are limitations to the power available from non-utility supply sources on the Island, this does not diminish the Company's responsibility to continue to endeavor to compile an adequate set of potential purchases from non-utility supply sources.

Accordingly, the Siting Council finds that Nantucket has developed a methodology for compiling an adequate resource set for purchases from non-utility supply sources.

Nantucket stated that, through its participation in the Collaborative Process, the Company has developed a comprehensive set of potential Company-sponsored C&LM measures (Exh. NAN-1, p. 1-7). The Company stated that it worked with the Conservation Law Foundation, Xenergy, Inc. ("Xenergy") and LaCapra Associates under the auspices of the Collaborative Process to identify and evaluate a full inventory of possible C&LM measures for its service territory (id., pp. 1-7, 1-8). Specifically, the Company stated that Xenergy developed a preliminary list of 41 residential and 37 commercial C&LM technologies with the potential to reduce energy consumption and/or reduce or shift peak demand on the Island (id., p. 4-1; Exh. HO-S-11). The Company did not identify C&LM resources developed by a third-party as a possible resource option.

Nantucket has identified a large number of C&LM measures based on a detailed review of C&LM technological potential for its customer base. Clearly, Nantucket's participation in the Collaborative Process has helped the Company to identify a wide variety of potential C&LM measures. Accordingly, the Siting Council finds that Nantucket has compiled an adequate set of C&LM resources. The Siting Council addresses the possibility of third party development of C&LM resources in Section III.D.3, below.

iii. Conclusions on Available Resource Options

The Siting Council has found that Nantucket identified a reasonable range of resource sets. The Siting Council also has found that Nantucket has compiled adequate sets of new Company-owned supply sources and C&LM resources. In addition, the Siting Council has found that Nantucket has developed a methodology which will allow it to compile an adequate resource set for purchases from non-utility supply sources. Accordingly, the Siting Council finds that Nantucket has demonstrated that it compiled a comprehensive array of available resource options.

b. Development and Application of Screening Criteria

To determine whether Nantucket developed and applied appropriate criteria for screening its array of available resource options, the Siting Council reviews the criteria developed and applied to each of Nantucket's three identified resource sets. Thus, the Siting Council reviews the criteria which were developed and applied to: (1) new Company-owned supply sources; (2) purchases of power from non-utility supply sources; and (3) new Company-sponsored C&LM resources.

Nantucket stated that it screened an array of new Company-owned supply sources using both cost and non-cost criteria (Exh. NAN-1, p. 5-23). Specifically, the Company stated that it screened Company-owned supply sources using the following criteria: (1) life-cycle costs; (2) technical feasibility; (3) siting feasibility; (4) policy; (5) risk; (6) potential environmental impact; and (7) fuel diversity (id., Exh. HO-S-9). Although the Company did not provide definitions for these criteria, it did explain why several of the identified Company-owned supply sources were eliminated based on these criteria (id., pp. 5-23 to 5-26).

The Company stated that a coal-fired plant was not considered to be a viable option for several reasons (id., p. 5-25). First, the Company stated that Nantucket's capacity requirements are too small for efficient coal plants, which are unavailable below a capacity of 12 MW to 15 MW (id.; Tr. 2, p. 154). Secondly, the Company stated that a coal plant would require a large amount of land, which is not available in downtown Nantucket and is expensive anywhere on the Island (Exh. NAN-1, p. 5-25). Finally, Nantucket stated that there is no source of coal on the Island, and that even a small coal-fired plant would require expensive new facilities for barging, handling, transporting and storing coal (id.).

Nantucket stated that propane currently is not available on the Island in sufficient quantities for electric generation, and that a propane-fired plant is not a viable option for many of the same reasons as for a coal-fired plant (id.). Specifically, the Company stated that a propane-fired plant would require a great deal of land and new support facilities for propane off-loading, handling and storage, which would require large capital outlays in addition to the cost of a new power plant (id., pp. 5-25 to 5-26; Tr. 2, p. 154). In addition, the Company stated that it would be very difficult to site a propane plant on the Island, and that such a plant would raise significant environmental concerns (Exh. NAN-1, p. 5-25).

With respect to the natural gas option, the Company stated that bringing natural gas to the Island via an underwater pipeline is not a viable option at this time because of the large capital costs of constructing such a pipeline (id., p. 5-26; Tr. 2, p. 153).

The Company did not provide any information on how it applied its screening criteria to oil-fired plants located offshore (id., p. 5-23). The record indicates that the Company did not consider oil-fired plants located offshore in its final evaluation of incremental resources (id., pp. 5-33 to 5-36).

Nantucket stated that there may be limited potential for wind power on the Island, but that wind turbines are not a viable option for baseload use because of the large amount of land required and the highly variable speed and wind direction changes on the Island (Exh. NAN-1, p. 5-25; Tr. 2, pp. 155-156). The Company further stated that wind turbines "should be considered for limited use" (Exh. NAN-1, p. 5-25).

However, the record indicates that the Company did not consider wind turbines in its final evaluation of incremental resources (id., pp. 5-33 to 5-36).

Nantucket stated that it relied on the results of a detailed study of the costs and technical feasibility of simple-cycle and combined-cycle combustion turbines and diesel generators performed for the Company by General Electric Company ("General Electric") to eliminate two potential Company-owned supply sources: combined-cycle combustion turbines and combined-cycle diesel generators (id., p. 5-26, Exh. HO-G-1h1).[43] The General Electric study examines several combined-cycle combustion turbines ranging in capacity from 3 MW to 20 MW (Exh. HO-G-1h1, p. 28). The study indicates that small combined-cycle combustion turbines are no more efficient, and in fact, may be substantially less efficient than simple-cycle combustion turbines (id.). The General Electric study further indicates that combined-cycle combustion turbines become economically attractive in sizes larger than 20 MW, but that the minimum capacity of such turbines is too large for Nantucket if system reliability is to be maintained (id., p. 29).[44]

The General Electric study also concluded that a combined-cycle diesel generator may be marginally viable on an economic basis, but that a substantial use for the low pressure steam must exist to justify such an arrangement (id., p. 30). However, Nantucket stated that there is no industrial sector on the Island, and that no potential user of low pressure steam has been identified or is likely to exist (Exh. NAN-1, p. 5-26).

The Company did not provide any information on how it applied its screening criteria to the three remaining

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43/ The study indicates that General Electric gave primary consideration to four criteria in its evaluation of these supply sources: generator efficiency, capital cost, operating complexity and system reliability (Exh. HO-G-1h1, p. 28).

44/ The General Electric study recommended that an incremental supply addition for Nantucket's system should not exceed 7 MW in capacity in order to maintain system reliability (Exh. HO-G-1h1, p. 25).

Company-owned supply sources identified by the Company: simple-cycle diesel generators; simple-cycle combustion turbines; or connecting Nantucket's system to the mainland via an underwater electric cable (id., p. 5-23). The record indicates, however, that the Company considered each of these three options in its final evaluation of incremental resources (id., pp. 5-33 to 5-36). See Section III.D.2, below, for a description of the Company's evaluation of these options.

Nantucket has set forth screening criteria which address both the cost and non-cost aspects of Company-owned supply sources. Generally, this set of criteria is reasonable. However, certain criteria such as "risk" and "policy" are susceptible to a variety of interpretations. In future filings, all criteria should be clearly defined. Nevertheless, the Siting Council finds that, for purposes of this review, Nantucket has established that it has developed appropriate criteria for screening Company-owned supply sources.

With regard to application of its screening criteria, Nantucket failed to provide documentation demonstrating that its screening criteria have been applied to Company-owned supply sources in a complete and consistent manner. In the past, the Siting Council has emphasized that a company is obligated to demonstrate that it has applied its screening criteria as part of a comprehensive supply planning process. 1990 MMWEC Decision, 20 DOMSC at 73; 1989 MECo Decision, 18 DOMSC at 338; 1989 BECo Decision, 18 DOMSC at 250-260; 1988 EUA Decision, 18 DOMSC at 111-123.

In most cases, Nantucket cited only how an option rated in terms of one or two of the Company's specified screening criteria, often the cost and siting feasibility criteria, and provided no information on how that option rated in terms of the Company's other criteria. Moreover, Nantucket failed to provide documentation that it applied its policy, risk and fuel diversity criteria to any of the Company's identified Company-owned supply sources.

The Company also failed to provide documentation regarding its application of non-cost screening criteria to three options which were considered in the Company's final evaluation of resources: simple-cycle diesel engines, simple-cycle combustion turbines, and underwater electric cables (see Section III.D.2.a.i, below). In addition, the Company failed to provide documentation regarding its application of either cost or non-cost screening criteria to the identified option of locating an oil-fired plant offshore, an option which was eliminated prior to the Company's final evaluation of resource options.

Finally, while the Company stated that wind turbines should be considered for limited use, it did not consider wind turbines in its final evaluation of incremental resources. The Company did not explain adequately why it eliminated wind turbines based on the Company's screening criteria, rather than fully evaluating the potential use of wind turbines as an option for meeting some portion of the Company's resource need.

Although Nantucket has established a reasonable set of criteria for assessing the relative merits of Company-owned supply sources, the Company has failed to provide persuasive evidence that its criteria are consistently applied across all new Company-owned supply sources. A consistent application of these criteria would provide Nantucket with a sound basis for analyzing each option's attributes and eliminating unacceptable options.

Accordingly, the Siting Council finds that Nantucket has failed to establish that it applied appropriate criteria for screening new Company-owned supply sources.

With regard to screening potential QFs and IPPs, the record indicates that Nantucket's current RFP filing includes the following criteria: purchase prices, payment schedules, contract length, financial coverage, site control, thermal energy use (if the proposed project is a cogenerator) and fuel supply (id.).[45] Nantucket specified minimum requirements or

45/ The Company did not provide any information regarding the applicability of these or any other screening criteria to the 28 potential self-generators on the Island (Exh. NAN-1, pp. 5-11, 5-12).

"threshold values" for each of these criteria for QF and IPP proposals in the Company's RFP process (Exh. HO-G-1d, pp. 20-22). The Company stated that each of these threshold values must be met in order for a proposed project to be eligible for inclusion in the Company's award group (id.). The Siting Council notes that Nantucket has not yet applied its threshold values to screen potential non-utility power purchases since the Company's RFP filing currently is under review by the MDPU.

In light of the MDPU's ongoing consideration of Nantucket's current RFP filing, the Siting Council makes no finding regarding whether the Company has developed and applied appropriate criteria for screening purchases from non-utility supply sources.

With regard to screening potential C&LM measures, Nantucket stated that it initially reviewed customer survey information to identify which of the preliminary list of 78 C&LM technologies developed by Xenergy exhibited significant market potential in the Company's service territory (Exh. NAN-1, pp. 4-1 to 4-8). Based on this review, the Company stated that it identified 19 potential technological measures associated with five end-uses (id., p. 4-2, 4-6). These 19 measures were then subjected to initial cost-effectiveness screening (id.).[46]

The Company stated that energy and peak savings estimates used in the initial cost-effectiveness screening for each of the potential C&LM measures were developed by Xenergy based on industry-wide experience with the technology and the penetration of the applicable end-use on the Island (id., p. 4-7). Nantucket stated that these estimated energy savings were translated into annual dollar savings by multiplying the energy saved in each period by the avoided costs for that period

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46/ Nantucket stated that the Company's avoided costs served as the benchmark for determining the cost-effectiveness of C&LM measures (Exh. NAN-1, p. 4-4).

(id.).[47] The Company further stated that technology costs also were developed by Xenergy based on its database of industry experience (id.).

Nantucket stated that, as part of its initial cost-effectiveness screening analysis, it calculated a benefit/cost ratio for each of the potential C&LM measures (id.).[48] The Company stated that it analyzed a range of alternative assumptions for the cost and energy savings of each C&LM measure (Exh. NAN-1, p. 4-7, Chapter 4, Appendix C). The Company indicated that all C&LM measures with a benefit/cost ratio of 1.0 or greater in any scenario passed the Company's initial cost-effectiveness screening process and were passed on to the final resource evaluation process (id., pp. 4-7, 4-8). The Company stated that this sensitivity analysis was valuable in evaluating C&LM measures which appeared to be marginal in terms of their cost-effectiveness (id., p. 4-7). The Company stated that it did not wish to screen such measures out prematurely and therefore included all such marginal measures in the Company's more detailed final evaluation phase (id.).

Nantucket noted that this "first pass" screening for cost-effectiveness did not include program or administrative costs (id.).

Nantucket stated that seven C&LM measures passed the Company's initial screen for cost-effectiveness (id., pp. 4-7, 4-8). The Company indicated that another seven C&LM measures were marginal, i.e., they had benefit/cost ratios which were either above or below 1.0 depending on the cost and energy savings assumptions used, but nonetheless were passed through

47/ Nantucket stated that its cost-effectiveness screening approach was developed in conjunction with consultants hired on behalf of the non-utility participants in Phase II of the Collaborative Process (id., pp. 4-6, 4-7). The Company stated that these consultants also reviewed the Company's avoided cost calculations (id.).

48/ The Company stated that this ratio was calculated by dividing the net present value of the estimated cost savings for a given C&LM measure by the estimated costs of that C&LM measure (Exh. NAN-1, p. 4-7).

the Company's initial screen for cost-effectiveness (id., pp. 4-7, 4-8, Chapter 4, Appendix C). Nantucket further stated that two C&LM measures which had a benefit/cost ratio of less than 1.0 under all scenarios were eliminated. Finally, the Company did not provide information on whether three other C&LM measures passed the Company's cost-effectiveness screening process.

Overall, Nantucket's development and application of screening criteria for C&LM measures is reasonable, well-documented, and exhibits significant strengths. Nantucket used the results of detailed customer surveys to narrow the potential C&LM options to those with a significant market potential on the Island and then performed a detailed preliminary analysis of the cost-effectiveness of these C&LM measures. The Company's use of its avoided costs as a basis for cost-effectiveness screening is appropriate, especially in light of the Company's further consideration of marginal C&LM measures. In addition, Nantucket's use of sensitivity analyses to examine the cost-effectiveness of C&LM measures under alternative assumptions is commendable. The Company's C&LM screening process clearly has benefited from the input of non-utility participants and consultants as part of Phase II of the Collaborative Process.

However, the Siting Council notes one weakness in the Company's C&LM screening process. The record indicates that Nantucket used only one non-cost criteria, market potential, in its C&LM screening process. We note that other electric companies have used a wide range of non-cost criteria, such as load impact and proven performance, in their C&LM screening processes. See 1990 MMWEC Decision, 20 DOMSC at 74-77. Moreover, the Company employs a number of non-cost criteria in the screening of utility-owned supply sources and purchases from non-utility supply sources.

Nonetheless, the Siting Council finds that, on balance, Nantucket has established that it has developed and applied appropriate criteria for screening its set of identified C&LM resources.

In sum, the Siting Council has found that Nantucket has established that it has developed appropriate criteria for screening Company-owned supply sources, but failed to establish that it applied appropriate criteria for screening such supply sources. The Siting Council made no finding regarding whether Nantucket has developed and applied appropriate criteria for screening non-utility supply sources. Finally, the Siting Council has found that Nantucket has established that it developed and applied appropriate criteria for screening C&LM options.

The Siting Council notes that Nantucket's process for identifying C&LM options is a significant strength in its overall resource identification process. For a company of Nantucket's size, such a thorough process is highly commendable. In addition, while the Siting Council made no finding regarding the Company's identification of non-utility supply sources, the Siting Council has found that the Company has developed a methodology for compiling an adequate resource set for purchases from non-utility supply sources. Accordingly, the Siting Council finds that Nantucket has, on balance, established that it has developed and applied appropriate criteria for screening its array of available resource options.

The Siting Council notes that Nantucket has developed three sets of screening criteria for its three identified resource sets which are quite distinct. While the use of distinct screening criteria may be justified in some cases, it is generally preferable to utilize a consistent set of criteria across resource sets to the extent possible in order to ensure that different types of resources are being screened in a consistent manner. Accordingly, the Siting Council ORDERS Nantucket in its next filing to develop and apply a consistent set of screening criteria to all of the Company's resource sets, or to justify the use of different screening criteria for different resource sets.

c. Conclusions on Identification of Resource Options

The Siting Council has found that Nantucket (1) demonstrated that it compiled a comprehensive array of available resource options, and (2) developed and applied appropriate criteria for screening its array of available resource options.

Accordingly, the Siting Council finds that Nantucket has established that it has identified a reasonable range of resource options.

2. Evaluation of Resource Options

The Siting Council reviews Nantucket's resource evaluation process to determine whether Nantucket (1) has developed a resource evaluation process which fully evaluates all resource options on an equal footing, and (2) has applied its resource evaluation process to all of the resource options identified in Section III.D.1, above.

In order to make this determination, the Siting Council first reviews Nantucket's resource evaluation process in terms of its ability to achieve the Company's overall supply planning objective of minimizing its annual revenue requirements while maintaining an acceptable level of reliability of service. The Siting Council next reviews Nantucket's resource evaluation process in terms of its ability to achieve the three additional objectives previously recognized by the Siting Council as integral to least-cost supply planning: enhancing diversity, minimizing risk, and minimizing environmental impacts. See 1990 MMWEC Decision, 20 DOMSC at 83; 1989 MECo Decision, 18 DOMSC at 362-363; 1989 BECo Decision, 18 DOMSC at 238, 270.

a. Company's Objective

As discussed in Section III.B, above, Nantucket stated that it defines a least-cost supply plan as the plan which achieves the overall objective of minimizing the Company's total revenue requirements while meeting the Company's reliability standard (Exh. NAN-1, p. 1-4). Further, the Company asserted that it evaluated all resource options on an equal footing in formulating its least-cost supply plan (id., pp. 1-7, 4-1). Thus, in this section, the Siting Council reviews the Company's application of its resource evaluation process to each of the three identified resource sets: Company-owned supply sources, purchases from non-utility supply sources, and Company-sponsored C&LM.

i. Company-Owned Supply Sources

(A) Description

The Company stated that it eliminated all but three generic Company-owned supply sources -- simple-cycle diesel engines, simple-cycle combustion turbines, and an undersea cable connection to the mainland -- in the Company's screening of its preliminary list of identified supply sources (Exh. NAN-1, pp. 5-24, 5-27 to 5-31). See Section III.D.1.b, above, for a detailed description of the Company's screening process for Company-owned supply sources. The record indicates that the Company examined five simple-cycle diesel engine manufacturer and size combinations, one simple-cycle combustion turbine option, and an undersea cable option in its final evaluation of the cost-effectiveness of supply sources (id., p. 5-31).

Nantucket stated that it evaluated and compared the cost-effectiveness of each of these supply sources over a period of 30 years in a series of detailed life cycle cost analyses (id., pp. 5-27, 5-31). The Company stated that these analyses included assessments of purchase costs, installation costs, ancillary equipment costs, supporting buildings and facilities costs, excavation and foundation replacement costs (where applicable), fuel and variable O&M costs,[49] and emission control equipment and permitting requirements costs (id., pp. 5-23 to 5-24, 5-29, 5-33). The Company stated that its life

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49/ Nantucket demonstrated that it evaluated one of its Company-owned supply source options (a diesel engine) using both the dealer's O&M cost estimate and a high O&M cost estimate based on a sample of manufacturers' estimates of O&M costs for similar units (Exh. NAN-1, p. 5-28).

cycle cost analyses took into account the annual revenue requirement created by a particular supply addition, plus the total fuel and variable O&M cost for the Company's entire generation mix (id., p. 5-33).

Nantucket indicated that each of the diesel engine supply sources and the combustion turbine supply source were evaluated in the Company's life cycle cost analyses using, where applicable, a consistent set of engineering and environmental assumptions in order to compare these supply sources on a consistent basis (id., pp. 5-31 to 5-32).[50] For example, the Company assumed that each new generator would require the same cooling system, utilize existing exhaust stacks, and have an economic life of 25 years (id., pp. 5-28 to 5-29). In addition, the Company assumed that Best Available Control Technology ("BACT") would be required for all new diesel engines and combustion turbines and indicated that the costs for BACT were incorporated in its life cycle cost analyses (id., p. 5-29).[51]

Although the record indicates that additional oil storage facilities may be required for the diesel engine and combustion turbine options, the Company did not demonstrate that it included any costs for additional oil storage tanks in its

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50/ The Company stated that it also evaluated certain non-cost characteristics of these supply sources such as reliability, parts availability, suitability for baseload operation, suitability for placement on existing foundations, heat rate at nameplate rating, and familiarity to plant operators (id., p. 5-29, Table 5-14). The Company did not specify, however, the manner in which these non-cost characteristics were incorporated in its evaluation process.

51/ The Company assumed that BACT would be Selective Catalytic Reduction ("SCR") technology for diesel engines and water injection for combustion turbines (Exh. NAN-1, p. 5-29). The Company stated that the use of SCR requires investment in new ammonia transport, handling and storage equipment (id., Exhs. HO-S-3; HO-RR-22). The Company stated that it incorporated estimates for the total cost of SCR technology, including ammonia equipment, in its life cycle cost analyses of diesel engines (Exh. NAN-1, p. 5-29). The record further indicates that the Nantucket Fire Chief has expressed concern regarding the storage of ammonia at the Company's existing downtown site (Exhs. HO-S-19).

analysis of these options (Exh. HO-G-1h1, p. 3).[52]

With regard to the undersea cable option, Nantucket stated that its life cycle cost analysis of a 60 MW cable[53] to the mainland assumed the installation of two sets of cables which would be laid in parallel trenches and extend 25 miles through Nantucket Sound to the mainland (Exh. NAN-1, p. 5-30; Tr. 2, pp. 168-169). The record indicates that the capacity of the 60 MW undersea cable option is approximately 2.4 times the Company's highest historical peak demand (Exhs. NAN-, p. 5-30, HO-4, p. 1). Nantucket stated that it did not calculate the cost-effectiveness of a smaller capacity cable such as the 27 MW and 50 MW options identified for the Company in a manufacturer's cost quote (Exh. HO-G-17e; Tr. 2, pp. 158-164).[54]

Nantucket stated that it assumed for the purposes of its cost evaluation that the Company would retain only its new combustion turbines as backup for restoring essential services

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52/ The record contains conflicting evidence regarding the need for additional oil storage facilities. General Electric, in its feasibility study on generation options conducted for the Company, stated that additional oil storage will be required if the Company decides to remain at the existing downtown facility and add new generation at that site (Exh. HO-G-1h1). General Electric noted, however, that the State Fire Marshall has stated that the existing storage of flammable and combustible liquids "in the heavily congested downtown area of Nantucket already constitutes both fire and explosion hazards" and concluded that "it is questionable whether authorities will allow this hazard to be expanded." Id. The Company stated, however, that it was uncertain whether it would be necessary to expand existing oil storage at the downtown site to accommodate the installation of a new diesel generator at that site (Tr. 2, pp. 118-119).

53/ The Company stated that a cable capacity of 60 MW was selected based on the need to have a sound engineering design rather than on the magnitude of Nantucket's supply requirements (Tr. 2, pp. 156-157).

54/ The record indicates that there may be significant differences in the capital costs of 27 MW and 60 MW submarine cables. Specifically, the cost quote provided to the Company states that the capital cost of a 27 MW cable would be $15.71 million to $16.85 million, while the Company estimated the capital cost of the 60 MW cable would be $23.95 million (Exhs. HO-G-17e, pp. 2, 4, NAN-1, Table 5-14, Table 5-15, Chapter 5, Appendix B).

in the event of a cable failure, and that the remainder of the Company's generation plant would be sold at a net salvage value of $5 million, which would be netted against the cost of the cable (Exh. NAN-1, p. 5-30; Tr. 2, p. 165).[55] The Company stated that the capital and O&M costs of the cable and ancillary equipment were based on manufacturer's quotes and reports prepared for the Company (Tr. 2, pp. 157-158, 166).

Nantucket further stated that its life cycle cost analysis of the undersea cable assumed that wholesale power would be purchased at the cost of the New England Power Service Company ("NEPCo") rate W-10 S, which the Company stated represented the low end of the New England wholesale electricity supply market (Exh. NAN-1, p. 5-30). The Company stated that it assumed that the cost of such power purchases would escalate at the rate of wholesale electric price increases forecasted by NEPOOL (Exh. HO-RR-18). Nantucket stated that it also assumed in its cost analysis that an undersea cable would have an economic life of 30 years, that it would take three years to install such a cable, and that the costs of siting and acquiring environmental permits for an undersea cable would be at least as expensive as for the construction of a new diesel generator (Exh. NAN-1, p. 5-31; Tr. 2, p. 164).[56]

55/ The Company stated that this cost estimate did not include any value for the sale of the land occupied by its downtown generation facilities (Exh. NAN-1, p. 5-30; Tr. 2, p. 167). The Company indicated that a significant portion of this land would be required for a new switching facility if an undersea cable was to be installed and that the remainder of the land was assumed to have no net value (Tr. 2, pp. 166, 167). The Company further explained that this property has been significantly devalued because it has been designated a "priority site" by DEP and likely would require the expenditure of substantial funds for the cleanup of toxic residue (Exhs. HO-G-5a, p. 16, HO-G-15, HO-G-17b; Tr. 2, pp. 167-168).

56/ The Company stated that it did not assign any value in its assessment of life cycle costs to the higher level of reliability (equal to a LOLP of one day in 10 years) of the power it would purchase from NEPCo relative to the Company's present reliability standard of a LOLP of one day in five years (Tr. 2, p. 171).

After completing the life cycle cost analyses for each of its Company-owned supply source options, Nantucket stated that it next compiled the annual revenue requirements for a series of alternative supply plans which differed only in the option(s) used as the incremental supply addition (id., pp. 5-31 to 5-33). The Company defined the least-cost first incremental supply addition as the addition which results in the supply plan which minimizes the net present value of the Company's total revenue requirements over the 30 year period of the analysis (id., pp. 1-5, 5-33).[57] The Company stated that its analysis indicates that the first incremental supply addition will be required in 1995 (id., p. 5-33). The Company noted that it also performed an equivalent analysis for the second incremental supply addition as well because the Company projects a need for a second supply addition in 1999, which is within the forecast period (id., pp. 5-35 to 5-37).[58]

Nantucket stated that the results of its life cycle cost analyses reveal that among its Company-owned supply source options, the 5.7 MW Colt-Pielstick diesel engine would minimize the net present value of the Company's total revenue requirements ($101.7 million over 30 years), and that this unit

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57/ Nantucket indicated that it used it's C&LM adjusted base case annual and peak forecasts in its life cycle cost analyses, and, for years beyond the scope of the Company's current forecast, assumed that annual electric use would grow at two percent per year and peak use would grow at four percent per year (id., pp. 5-18, 5-31).

58/ The Company stated that in its evaluation of the options for a least-cost supply addition, it assumed that when supply, including the incremental addition, can no longer meet the installed capacity and reserve requirements mandated by the Company's reliability standard in a particular year, energy and capacity deficiencies were assumed to be supplied at the average avoided energy cost and/or the peak avoided capacity cost in that year (Exh. NAN-1, p. 5-33). The Company explained that these future avoided energy and capacity costs were based on the cost of a typical diesel engine, escalated to the relevant year(s) (Tr. 2, pp. 178-180). The Company argued that these costs were reasonable because the Company can continue to expand capacity at its existing downtown and airport generation sites for approximately 30 years before it would need to locate generation at a new site (id., pp. 180 to 182).

therefore is the Company's least-cost first incremental supply addition (id., p. 5-33).[59, 60]

The Company stated that its second incremental capacity addition analysis indicates that the 4.4 MW Caterpillar diesel engine would be the least-cost alternative for the Company's second supply addition (id., p. 5-37).

(B) Analysis

In general, the Company's methodology for evaluating its identified Company-owned supply source options is sound. In particular, the Company's use of life cycle cost analysis is an appropriate means for comparing the cost-effectiveness of alternative supply sources. In addition, with relatively few exceptions, the assumptions employed by Nantucket in these analyses are reasonable and well documented. These assumptions generally were based on manufacturer's quotes or published reports. The Company's use of a consistent set of engineering and environmental assumptions to compare alternative supply sources is appropriate.

However, the Company's cost analyses also exhibit several weaknesses. First, with the exception of the O&M costs of one diesel engine option, the Company failed to demonstrate that it examined the sensitivity of its results to changes in major cost assumptions. In the past, the Siting Council has stated that the use of sensitivity analyses can contribute to a more complete evaluation of a resource's cost-effectiveness. 1990 MMWEC Decision, 20 DOMSC at 87-88. Moreover, we have commended

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59/ The Company assumed in its life cycle cost analyses for its first incremental supply addition that, if the Company added a new diesel engine or combustion turbine generator, the Company would not need to retire any existing generators other than Unit 2, and that the remaining generators would continue to operate until 2019 (Exh. NAN-1, Chapter 5, Appendix B; Tr. 2, pp. 186-189).

60/ The Company's calculations indicated that the Company-owned supply source option which results in the highest total revenue requirements is the 60 MW undersea cable option, which would cost $136.7 million over 30 years on a net present value basis (Exh. NAN-1, p. 5-33).

Nantucket in previous sections of this decision for its use of multiple load scenarios and sensitivity analyses as a means of examining the reliability of the Company's forecasts given the existence of uncertainty in its assumptions. However, with the minor exception noted above, Nantucket failed to demonstrate that it conducted sensitivity analyses of the major assumptions in its least-cost supply analysis. In fact, a number of these assumptions, including the fuel costs and the maximum capacity of the Company's existing facility sites, appear to be subject to a significant degree of uncertainty. The Siting Council notes that for a supply plan to be truly least-cost, it must prove to be least cost over a significant range of plausible assumptions.

The Siting Council anticipates that in its next filing, Nantucket will incorporate sensitivity analyses for its major assumptions, including the capital costs, fuel costs, expected life of different supply options, the need for new ancillary facilities or modifications to existing facilities, the costs of power purchased through the undersea cable, and the maximum capacity of the Company's existing facility sites into the Company's cost analyses of Company-owned supply sources.

Second, the Company did not examine an adequate range of supply scenarios involving the construction of an undersea cable to the mainland. For example, the Company did not analyze the cost-effectiveness of constructing a smaller undersea cable and continuing to operate all or some portion of the Company's existing downtown generators. Accordingly, the Siting Council ORDERS Nantucket in its next filing to examine (1) the cost-effectiveness of operating a broad range of undersea cable sizes, and (2) the cost-effectiveness of operating such cables in conjunction with all or some portion of the Company's existing downtown generators.

Third, the Company's failure to consider the potential need to retire and replace existing units in its cost analyses for its first incremental supply appears to bias the results of its analyses in favor of the diesel engine and combustion turbine options. Given the condition of the Company's existing generators, the Company's assumption that none of these units (except Unit 2) will have to be replaced within the next 30 years is implausible. (See Section III.C.2.b, above, for a discussion of reliability concerns regarding these generators). The Company's analysis of the undersea cable option assumes that all of the Company's existing generators except for the Company's new combustion turbines would be sold, which eliminates the future expense of replacing these facilities as they are retired. The impact of Nantucket's assumption regarding the retirement of existing units is to inappropriately reduce the projected costs of the diesel and combustion turbines relative to the undersea cable.

Fourth, the Company inappropriately failed to assign any value to the higher reliability of power that would be available from purchases through the undersea cable. While the Siting Council previously has found that the Company's reliability criterion is appropriate, that criterion was in part based on a consideration of the cost of various levels of reliability. The Company's failure to consider the reliability benefits of one supply option relative to others, particularly where such benefits are significant, contradicts the stated objective of the Company's supply planning process, which incorporates both cost and reliability considerations.

Accordingly, the Siting Council ORDERS Nantucket in its next filing to (1) incorporate realistic assumptions regarding the timing of the retirement of existing generators and the costs to replace such generators in its least cost supply analyses, and (2) consider the benefits of the higher reliability of power purchased through an undersea cable in its least-cost supply analyses.

Finally, the Siting Council is concerned that Nantucket may not have adequately considered potential siting difficulties associated with its diesel engine and combustion turbine supply source options in its resource evaluation process. Specifically, the Siting Council is concerned that the Company did not adequately consider the possible siting difficulties related to necessary new ammonia facilities and/or the expansion of oil storage facilities for diesel generators to be sited at the Company's downtown site. While a detailed siting feasibility study should not be necessary to make initial supply planning decisions, the likelihood of being able to implement individual supply planning decisions must be considered in the resource evaluation process. Difficulties in constructing or permitting planned facilities may significantly impact the costs and availability of supply options.

Accordingly, the Siting Council ORDERS Nantucket in its next filing to: (1) examine the practical limitations, if any, on the storage of ammonia and diesel oil at the Company's existing downtown site; (2) analyze and discuss the implications of any such limitations on the Company's ability to increase the total generation capacity located at the downtown site and to operate that capacity in an adequate manner; and (3) incorporate the Company's findings in parts (1) and (2) into the Company's least cost supply analyses.

Although Nantucket has incorporated several questionable assumptions in its life cycle cost analyses of Company-owned supply sources, overall the Company's cost methodology exhibits significant strengths, and the majority of the Company's assumptions are sound. Accordingly, the Siting Council finds that, on balance, Nantucket's methodology for achieving the Company's objective of minimizing annual revenue requirements while maintaining reliable service, as applied to its evaluation of Company-owned supply sources, is appropriate.

ii. Purchases from Non-Utility Supply Sources

As noted in Section III.D.1.b, above, Nantucket's current RFP filing before the MDPU will allow for bids from QFs and IPPs (Exh. HO-G-1d; Tr. 2, pp. 28, 65). Nantucket's solicitation includes criteria and weights for evaluating potential bids for power purchases from third party developers (Exh. HO-G-1d). Specifically, the Company stated that a QF/IPP proposal would be evaluated based on a number of criteria, including: (1) the net economic benefits to the Company's ratepayers over the life of the power sales contract; (2) the impact on ratepayers during the initial years of the contract term; (3) the proposed facility's ability to meet the operational needs of the Company's system; (4) risk to the Company's ratepayers; and (5) environmental externalities (id., p. 11, Exh. HO-RR-11; Tr. 2, pp. 28-30). The Company further indicated that the costs of purchases from a QF or IPP would be evaluated relative to the Company's avoided costs (Exh. HO-G-1d, pp. 15, 20).

The Company stated that its planned first incremental supply addition, or subsequent planned additions, might be avoided or delayed in whole or in part by purchases from QFs and IPPs (id., pp. 6, 15). However, the Company indicated that the likelihood of a significant response to the RFP was low because of the limited opportunities for development on the Island (Tr. 2, p. 151).

In light of the MDPU's ongoing consideration of Nantucket's current RFP filing, the Siting Council makes no finding regarding whether Nantucket's methodology for achieving the Company's objective of minimizing annual revenue requirements while maintaining reliable service, as applied to its evaluation of purchases from non-utility supply sources, is appropriate.

iii. Conservation and Load Management

Nantucket estimated that Company-sponsored C&LM programs would achieve savings of 4,238 MWH in 1996 and would reduce winter peak load by 1.392 MW in that same year (id., pp. 4-10, 4-11).[61] The Company stated that it derived these estimates

61/ The Company stated that it made a simplifying assumption that peak and annual energy savings from Company-sponsored C&LM programs would remain constant at 1996 levels after 1996, i.e., that no net additional Company-sponsored C&LM would occur after 1996 (Exhs. HO-S-12, HO-S-26). The Company justified this assumption by stating that, because the Company is just beginning to institute a broad array of new C&LM programs, the Company had no basis for forecasting C&LM impacts beyond the current time frame of these programs, which extend through 1995 for the residential sector and 1996 for the commercial sector (id.).

externalities[64] and appropriate C&LM measure lifetimes (id.). The record indicates that nearly all of the C&LM program plans are expected to have a benefit/cost ratio greater than 1.0, and therefore are cost-effective (id., Chapter 4, Appendix D).

The Company provided detailed information on its customer participation goals for those C&LM programs which had passed the Company's final cost-effectiveness test (id., pp. 4-12 to 4-29). The Company stated that the C&LM penetration rates embodied in these goals were the maximum achievable on Nantucket given the Company's and the Island's limited resources (Exhs. HO-S-11, HO-S-25). Nantucket also provided detailed technical analyses of the expected energy and capacity savings that it expected to realize from its C&LM programs (Exh. NAN-1, Chapter 4, Appendix E).

The Company stated that it will institute a program monitoring and evaluation process to track ongoing program costs and savings by end-use and by sector (id., p. 4-30). Nantucket stated that it plans to file with the MDPU for preapproval of its planned C&LM programs in the near future (Exh. HO-S-27). The Company provided figures showing that implementation of its planned C&LM programs would place Nantucket among the leading electric companies in Massachusetts in terms of company-sponsored C&LM expenditures relative to revenues (Exh. HO-RR-13).

The Siting Council notes that Nantucket's array of C&LM programs is impressive for a company of its size. Clearly, the Company has benefited from its participation in the Collaborative Process. Moreover, the Company's final cost-effectiveness test, which employed data which was consistent with the Company's evaluation of other resource

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64/ The Company indicated that it accounted for the lack of environmental externalities associated with C&LM measures relative to traditional supply options by giving a 20 percent bonus to C&LM, i.e., by setting an upper limit for cost-effectiveness of 120 percent of avoided costs (Tr. 2, p. 66). The Company stated that this 20 percent bonus value approximately equaled the aggregate cost of the set of environmental externalities proposed by the MDPU (id., p. 67).

options, is an appropriate means for evaluating C&LM resources. In addition, Nantucket developed estimates for the savings from the Company's C&LM programs based on a reasonable technical assessment of such savings.

The Company's use of a "bonus" to account for the environmental benefits of C&LM is commendable. The Company's choice of a 20 percent value for such a bonus based on MDPU indications of the monetized cost of certain environmental externalities of supply options is appropriate at this time. (See Section III.D.2.b, below, for a discussion of the incorporation of environmental factors into the Company's supply planning process).

In addition, the Company's C&LM program monitoring and evaluation process will provide the Company with accurate cost and savings data as the Company implements its C&LM programs over time.

Nevertheless, the Siting Council notes two concerns regarding Nantucket's development of estimates for the energy savings that it expects to obtain from planned Company-sponsored C&LM programs. First, the Company's assumption that C&LM savings would remain constant after 1996 is questionable. The Siting Council acknowledges that it would be difficult for Nantucket to accurately estimate long-term C&LM impacts in light of the fact that the Company is still formulating its final C&LM programs. To the extent that the Company will continue to invest in additional C&LM resources after this period, however, the Company's C&LM-adjusted demand forecast will be overstated after 1996 since it does not currently reflect any such additional investments. Second, Nantucket did not fully substantiate how it determined that the Company's goals represent the "maximum achievable" C&LM penetration rates on the Island or that the Company will be able to fully realize such goals.

The Siting Council anticipates that, as the Company begins to obtain actual data on the cost-effectiveness and energy savings from the installation of C&LM, the Company will have a reasonable basis for forecasting the expected energy savings from C&LM throughout the forecast period. Given such data, the Company should be able to correct the two problems noted above.

Accordingly, the Siting Council finds that, on balance, Nantucket's methodology for achieving the Company's objective of minimizing annual revenue requirements while maintaining reliable service, as applied to its evaluation of C&LM, is appropriate.

iv. Conclusion on Company's Objective

The Siting Council has found that Nantucket's methodologies for achieving the Company's objective of minimizing annual revenue requirements while maintaining reliable service, as applied to its evaluation of (1) Company-owned supply sources, and (2) C&LM, are appropriate. The Siting Council has made no finding regarding Nantucket's methodology for achieving the Company's objective of minimizing annual revenue requirements while maintaining reliable service, as applied to purchases from non-utility supply sources. Accordingly, the Siting Council finds that, on balance, Nantucket's methodology for achieving its objective of minimizing annual revenue requirements while maintaining reliable service is appropriate.

b. Other Objectives

As noted in Section III.D.2, above, the Siting Council, in previous decisions, has recognized three objectives, in addition to the cost and reliability objective identified by the Company, which are integral to least-cost supply planning: enhancing diversity, minimizing risk, and minimizing environmental impacts. Specifically, in previous decisions, the Siting Council has accepted the incorporation of diversity and/or risk minimization in electric companies' supply planning objectives. 1990 MMWEC Decision, 20 DOMSC at 79; 1989 MECo Decision, 18 DOMSC at 362-363; 1989 BECo Decision, 18 DOMSC at 238, 270. In addition, the Siting Council's enabling statute directs us to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H.

Thus, in this section, the Siting Council analyzes the extent to which Nantucket implicitly incorporates these three objectives -- enhancing diversity, minimizing risk and minimizing environmental impacts -- in its supply planning process.

An electric company may address diversity in a number of ways. In previous cases, electric companies have addressed diversity in terms of: (1) types of fuel supply; (2) types of generation technology; and (3) whether resources are company-owned or provided by third parties. 1990 MMWEC Decision, 20 DOMSC at 87-89; 1989 MECo Decision, 18 DOMSC at 363-365. In the current proceeding, Nantucket stated that it evaluates the costs and benefits of fuel diversification "from time to time," but that "by virtue of its isolation, size, limited port facilities and limited land resources, the choices available to the Company are restricted" (id., p. 5-26). The Company did not explicitly address diversity in terms of types of generation technology or whether resources are company-owned or provided by third parties.

Although Nantucket did not explicitly include diversity in its stated supply planning objective, the record demonstrates that the Company's supply planning process identified a diverse set of resource options in terms of C&LM versus traditional supply options, fuel type, type of generation technology, and company-owned resources versus purchases from third parties. The record further indicates that many of these options were screened out of the Company's supply plan because they were either technically, economically, or environmentally infeasible on the Island. Clearly, Nantucket, as a result of the Island's small physical size and isolation, faces unique constraints which significantly limit the Company's ability to diversify its resource portfolio. Accordingly, the Siting Council finds that Nantucket's methodology for evaluating resource options adequately considers diversity. The Siting Council notes that the Company's new C&LM programs will provide a degree of diversity to the Company.

An electric company also may address risk in a number of ways. In previous cases, electric companies have addressed risk minimization by means of: (1) incorporating multiple scenarios into their demand forecasts to address uncertainty in the need for new supplies; (2) formulating action plans to address supply contingencies; and (3) minimizing financial risk through purchases from third parties. 1990 MMWEC Decision, 20 DOMSC at 88-91; 1989 MECo Decision, 18 DOMSC at 366-368; 1989 BECo Decision, 18 DOMSC at 238-239, 271-272. The record in this proceeding shows that Nantucket has developed multiple demand scenarios, action plans to address supply contingencies, and a reasonable reliability standard, all as means of minimizing risk in its supply plan.

Although Nantucket did not include risk explicitly in its stated supply planning objective, the Company's use of low case, base case, and high case demand scenarios demonstrates that the company has considered the risk of demand growing at a slower or higher rate than its base case forecast. The Siting Council also has found in Section III.C, above, that Nantucket has developed an acceptable reliability standard and action plans to address supply contingencies. Further, the record indicates that the Company currently is seeking MDPU approval of its RFP process for QF/IPP purchases. If successfully implemented, such a RFP process would allow the Company potentially to reduce its financial risk by purchasing power from third-party developers rather than adding new Company-owned supplies. Accordingly, the Siting Council finds that Nantucket's methodology for evaluating resource options adequately considers risk.

In previous decisions, the Siting Council has considered whether an electric company has attributed environmental impacts or benefits to different resource options. 1990 MMWEC Decision, 20 DOMSC at 93-95; 1989 MECo Decision, 18 DOMSC at 368-369; 1989 BECo Decision, 18 DOMSC at 270.

In its brief, Nantucket stated that the Company's objective is to "minimize the annual revenue requirement and environmental impact, given an established level of reliability"

(Company Brief, p. 52). However, the record does not indicate that the minimization of environmental impacts is explicitly incorporated in the Company's statement of its overall objective (Exh. NAN-1, p. 1-4). Nantucket argued that it has met the objective of minimizing environmental impacts "through the review of all resource options, the commitment to pursue all cost-effective C&LM options (including the effects of environmental externalities), and through compliance with all environmental permitting and licensing requirements" (Company Brief, p. 52). With regard to its evaluation of purchases from non-utility supply sources, the Company provided a series of tables depicting the external cost of selected air emissions for use in its current QF/IPP RFP filing using (1) MDPU estimates of the external costs of these emissions, and (2) Company-proposed modifications to these MDPU estimates (Exh. HO-RR-11). The Company further stated that the incorporation of environmental externalities would make certain types of projects (e.g., renewable energy) more attractive in the solicitation process (Tr. 2, pp. 29-30).

The Siting Council notes that while Nantucket provided a 20 percent bonus to C&LM options to reflect the environmental benefits associated with such options, the Company did not consider environmental externalities in its evaluation and selection of Company-owned supply options. However, the Company stated that it would incorporate environmental externalities in its evaluation of all resource options, including Company-owned supply sources, in the future (Tr. 2, pp. 30-31).

Nantucket's recognition that environmental factors play an important role in supply planning and its concrete plans to incorporate environmental externalities into its evaluation of all resources in the future are commendable. The Siting Council notes, however, that the Company's evaluation of environmental factors should not focus exclusively on air emissions, but rather should include all relevant environmental factors, including those which are not readily subject to quantification. Accordingly, the Siting Council ORDERS

Nantucket in its next filing to develop and implement a resource evaluation process for all resource options which includes a full consideration of environmental impacts. Accordingly, the Siting Council finds that, for the purposes of this review, Nantucket's methodology for evaluating resource options adequately considers environmental impacts.

c. Conclusions on the Resource Evaluation Process

The Siting Council has found that Nantucket's methodology for achieving its objective of minimizing annual revenue requirements while maintaining reliable service is appropriate. The Siting Council also has found that Nantucket's methodology for evaluating resource options adequately considers diversity, risk, and environmental impacts.

Based on the foregoing, the Siting Council finds that Nantucket has established that it has (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all resource options.

3. Consistency of Supply Planning Process With IRM Objectives

The Siting Council notes that the MDPU exempted Nantucket from the Integrated Resource Management ("IRM") process because of Nantucket's small size and geographic isolation (DPU 89-239, August 31, 1990 ("MDPU IRM Order"), p. 50).[65] In exempting Nantucket from the IRM process, however, the MDPU explicitly recognized that the Siting Council will consider, as part of its review of the Company's supply plan, whether Nantucket's supply planning process meets the objectives of the IRM process (id.).

65/ The Siting Council hereby takes administrative notice of this decision of the MDPU. The IRM process establishes a regulatory framework through which most electric companies operating in the Commonwealth will acquire new resources.

Nantucket stated that the major objective of the IRM process is to ensure that utility resource plans are least cost, environmentally sound, and reliable (Company Brief, p. 75). The Company argued that the Siting Council's detailed review of the Company's supply plan, pursuant to the Siting Council's statutory objective to ensure that utility resource plans are reliable and appropriate for meeting customers' needs in a least cost and environmentally sound manner, ensures that the IRM objectives are met (id.). In addition, the Company argued that (1) it has successfully developed a least-cost supply planning process that conforms with the IRM objectives, and (2) the Company is subject to the MDPU's regulations for C&LM preapproval, QF solicitations, and cost recovery associated with the addition of new resources (id., pp. 75, 76).

In Sections III.D.1 and 2, above, the Siting Council has accepted Nantucket's process for identifying and evaluating resource options. In particular, the Siting Council has commended Nantucket's process for identification and evaluation of C&LM options. However, the Siting Council also has noted weaknesses in the Company's resource planning process in regard to the application of the Company's criteria on a consistent basis and in regard to the use of consistent criteria across resource options where appropriate. The Siting Council has included a series of orders in this decision which will require Nantucket to address these weaknesses in its next filing. In particular, the Siting Council notes two related areas in which the Company's process for identifying and evaluating resource options diverges from the IRM process.

First, the IRM process allows electric companies to evaluate and purchase both demand-side and supply-side resources from third party developers (id.). However, Nantucket has no process in place which would permit bidding or allow negotiation with third party C&LM developers.

The Siting Council notes that Nantucket may be able to benefit from the purchase of C&LM resources from third party developers, either through direct negotiations or through incorporation of C&LM resources into future resource solicitations.

Second, the IRM solicitation enables companies to evaluate both company-owned and third party demand-side and supply-side resources within a unified framework. In contrast, the Company's current supply planning process evaluates company-owned supply resources, company-sponsored C&LM resources and QF/IPP resources through three completely separate and non-coincident processes.

Nantucket's current supply planning process clearly is not as comprehensive as the IRM process. We recognize, however, that implementing an IRM-like framework that achieves all of the goals of the IRM process likely would require significant expenditures which would not be warranted for a company of Nantucket's size. The Siting Council notes that the Company's supply planning process does incorporate many of the fundamental objectives of the IRM process. In addition, the Company's stated plans to improve its process, combined with its compliance with the orders contained in this decision, will bring the Company's supply planning process even closer in line with the goals of the IRM process.

Accordingly, the Siting Council finds, for purposes of this review, that Nantucket has established that its supply planning process satisfies the objectives of the IRM process.

4. Conclusions on Least-Cost Supply

The Siting Council has found that Nantucket has identified a reasonable range of resource options. The Siting Council also has found that Nantucket has established that it (1) developed a resource evaluation process which fully evaluates all resource options, including the treatment of all resource options on an equal footing, and (2) applied its resource evaluation process to all its identified resource options. Further, the Siting Council has found that Nantucket has established that its supply planning process satisfies the objectives of the IRM process.

Accordingly, the Siting Council finds that, on balance, Nantucket has established that its supply plan ensures a least-cost energy supply.

E. Previous Supply Plan Review

In the 1987 Nantucket Decision, the Siting Council rejected Nantucket's supply plan. In that decision, the Siting Council included the following orders:[66, 67]

> 8. That the Company shall provide an update on its contingency action plan for 1988. The update should include documentation of any firm load shedding agreements that the Company expects to rely upon in the event of a single contingency supply deficiency under peak load conditions. The Company should also set out and explain the order in which it would implement load shedding and rotating service blackouts.
>
> 9. That the Company update its analysis of specific demand-side measures in order to determine which are most cost-effective and which should be implemented. This update should be based on new audit information and the Company's further research. Cost information should be provided even for measures that appear to offer only small capacity savings. Cost analyses should [be] presented in such a way that the Company can compare the cost to the system of implementing demand management against the cost to the system of adding equivalent capacity and/or of producing energy over the lives of the demand and supply side options.
>
> 10. That the Company present specific plans for meeting all forecasted peak load requirements in the short-run. Such plans should include information on the sizing, timing, siting and costs for any proposed capacity expansion, and expected capacity and energy savings and costs for any demand-side management. The Company must demonstrate that, in developing those plans, it has explored a reasonable range of demand-side management and generation options and has evaluated them on an equal basis.

66/ The numbers preceding each order correspond to their order of presentation in the 1987 Nantucket Decision.

67/ Nantucket previously complied with Orders 1 and 2 of the 1987 Nantucket Decision. Order 1 required the Company to update the Siting Council on its progress in obtaining approvals for and installing a 3.6 MW diesel engine. Order 2 required the Company to present a contingency action plan for 1987. On July 6, 1987, the Hearing Officer reported to the Siting Council that Nantucket had complied with Orders 1 and 2.

11. That the Company provide a discussion of its long-range supply planning process, including all approaches to changing the type, size and location of the Company's generating plant and integrating demand-side management measures into the Company's supply plan. The Company should explain how its planning process includes consideration of long-run environmental constraints, transmission system issues under split-plant operation, and options for capacity relocation under a split plant configuration. The Company also should explain how its planning process includes consideration of objectives for establishing optimal reserve capacity criteria for different times of the year.

In response to Order 8, the Company provided an update of its contingency action plan for 1990 (Exh. NAN-1, pp. 1-21, 5-37, 5-38). Specifically, Nantucket stated that in the event of a loss or delay of a needed supply option, the Company would rent a trailer-mounted diesel unit until the situation was corrected, and in the event of higher than expected demand growth, the Company would accelerate its current plan to purchase a new unit or rent a trailer-mounted diesel unit (id., pp. 5-37, 5-38). Nantucket also described a set of emergency procedures, based on NEPOOL operating procedures, which the Company has developed for operating during critical load periods (id., p. 1-21). Further, the Company set forth the order in which it would implement load shedding under its emergency operating procedures in the event that such load shedding is required (Exh. HO-G-4). Accordingly, the Siting Council finds that Nantucket has complied with Order 8 of the 1987 Nantucket Decision. (A more detailed description and analysis of the Company's contingency plan is provided in Section III.C, above.)

In response to Order 9, the Company provided detailed information on its current and proposed C&LM programs (Exh. NAN-1, pp. 1-21, 1-22, Chapter 4). The Company stated that: (1) it has developed a new C&LM plan through its participation in Phase II of the Collaborative Process (id., p. 4-1); (2) it has evaluated the technological potential and cost-effectiveness of over 78 energy-saving C&LM technologies (id., p. 1-21); and (3) it has evaluated the cost-effectiveness of potential C&LM measures using the avoided cost and societal cost tests (id., pp. 1-21, 1-22, 4-2 to 4-4). Accordingly, the Siting Council finds that Nantucket has complied with Order 9 of the 1987 Nantucket Decision. (A more detailed description and analysis of the Company's supply planning process is provided in Section III.B, above. A more detailed description and analysis of the Company's C&LM plan is provided in Section III.D, above.)

In response to Order 10, the Company provided (1) a detailed supply plan including the Company's current plans to meet projected peak loads in the short-run (id., 1-10, 1-11, Table 1-3, Chapter 5), and (2) information on the size, timing, siting and costs of the Company's proposed capacity expansions as well as the expected capacity and energy savings and costs of the Company's planned C&LM programs (id., pp. 4-9 to 4-12, 5-15, 5-16, 5-27 to 5-37). In addition, the Siting Council found in Section III.D, above, that the Company has explored a reasonable range of demand-side and supply-side alternatives and has evaluated them on an equal footing. Accordingly, the Siting Council finds that Nantucket has complied with Order 10 of the 1987 Nantucket Decision.

In response to Order 11, the Company provided a detailed discussion of its long-run supply planning process, including issues relating to the type, size and location of the Company's generating plant and integrating C&LM measures into the Company's supply plan (id., Chapters 4 and 5, Exh. HO-S-6). As discussed in Section III.D.2.a.i, above, the Siting Council is concerned that the Company has not adequately addressed possible long-run environmental constraints related to the siting of required ammonia and oil storage facilities in its supply planning process. The Company provided a discussion of current transmission issues and stated that split-plant operation does not constitute a problem in this regard (Exhs. NAN-1, pp. 5-38 to 5-41, Chapter 5, Appendix D, HO-G-4). The Company also provided detailed information on options for capacity relocation under a split-plant configuration (Exhs. HO-G-1h1, HO-S-6). Finally, the Company provided detailed information on optimal reserve margin capacity objectives for different times of the year (Exh. NAN-1, pp. 5-6 to 5-10, Chapter 5, Appendix A, Tables 5-1, 5-9, 5-11 and 5-12).

Accordingly, the Siting Council finds that Nantucket has complied with the first, third, fourth and fifth parts of Order 11 of the 1987 Nantucket Decision but that the Company failed to comply with the second part of Order 11 of the 1987 Nantucket Decision regarding the incorporation of environmental constraints in its supply planning process. A more detailed description and analysis of the Company's supply planning process is provided in Section III.B, above. A more detailed description and analysis of the Company's optimal reserve capacity criteria is provided in Section III.C.1, above.

F. Conclusions on the Supply Plan

The Siting Council has found that Nantucket has established that its supply plan ensures adequate resources to meet projected requirements. The Siting Council has also found that Nantucket has established that its supply plan ensures a least-cost energy supply.

The Siting Council also has found that Nantucket complied with Orders 1, 2, 8, 9, 10 and the first, third, fourth and fifth parts of Order 11 of the previous Nantucket decision and has failed to comply with the second part of Order 11.

Nantucket has demonstrated considerable progress in its supply planning process. Specifically, the Company has developed an appropriate process for identifying and evaluating least cost supplies. The Siting Council has noted concerns regarding certain of Nantucket's criteria and its failure to document that it has applied all of its criteria to all of the identified resource options. Nevertheless, the problems with the Company's supply planning process are outweighed by its substantial progress. We also expect that further progress will be made as the Company complies with the orders contained in this decision.

Accordingly, the Siting Council hereby APPROVES Nantucket's 1990 supply plan.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the 1990 demand forecast and APPROVES the 1990 supply plan of Nantucket Electric Company.

The Siting Council ORDERS Nantucket Electric Company in its next forecast filing to:

(1) utilize distinct economic/demographic scenarios for its base case, low and high case forecasts of annual electricity demand;

(2) incorporate historical and projected electricity prices explicitly into its residential and commercial sales forecasts;

(3) reexamine and provide a full explanation of all assumptions made regarding residential appliance type saturation levels and penetration rates in light of both recent experience and long-term historical trends on Nantucket;

(4) file separate forecasts for (1) the residential heating sector, and (2) the residential non-heating sector;

(5) evaluate and report on the potential benefits and difficulties of incorporating commercial floor space into its commercial forecast methodology;

(6) identify additional commercial end uses to be disaggregated, or to fully justify the present level of commercial end-use disaggregation;

(7) reexamine and provide a full explanation of all assumptions made regarding commercial appliance type saturation levels and penetration rates in light of both recent experience and long-term historical trends on Nantucket;

(8) fully document and justify its selection of base year and projected energy intensity values for its commercial forecast;

(9) normalize historical demand data for weather in projecting peak demand;

(10) develop and present an improved peak load forecasting methodology which incorporates (1) the results of the Company's ongoing load research and computerized billing research, and (2) major underlying factors of peak load such as weather effects, seasonal consumption patterns, and price effects;

(11) (1) estimate the impact of potential resource additions on the reliability and life expectancy of the Company's existing generators, and (2) document its consideration of this impact in its determination of the appropriate timing of incremental resource additions;

(12) provide detailed information on the Company's plans and ability to secure financing for resource additions planned for the short run;

(13) develop and apply a consistent set of screening criteria to all of the Company's resource sets, or to justify the use of different screening criteria for different resource sets;

(14) examine (1) the cost-effectiveness of operating a broad range of undersea cable sizes, and (2) the cost-effectiveness of operating such cables in conjunction with all or some portion of the Company's existing downtown generators;

(15) (1) incorporate realistic assumptions regarding the timing of the retirement of existing generators and the costs to replace such generators in its least-cost supply analyses, and (2) consider the benefits of the higher reliability of power purchased through an undersea cable in its least-cost supply analyses;

(16) (1) examine the practical limitations, if any, on the storage of ammonia and diesel oil at the Company's existing downtown site; (2) analyze and discuss the implications of any such limitations on the Company's ability to increase the total generation capacity located at the downtown site and to operate that capacity in an adequate manner; and (3) incorporate the Company's findings in parts (1) and (2) into the Company's least-cost supply analyses;

(17) develop and implement a resource evaluation process for all resource options which includes a full consideration of environmental impacts.

In addition, the Siting Council ORDERS Nantucket to provide by July 8, 1991:

(18) (1) an update of the status of the air permits for Units 10 and 11, and (2) a copy of any new permit or permit extension for Units 10 and 11 received by the Company from DEP.

The Siting Council recognizes that the preparation of a forecast and supply plan filing requires significant financial expenditures which can place a significant and disproportionate burden on a small company such as Nantucket. In addition, the current decision includes a large number of orders which will take time for the Company to implement. Accordingly, the Siting Council will adopt a schedule for reviewing Nantucket's future forecast and supply plans which is compatible with the schedule established for electric companies which are subject to IRM. See EFSC 90-RM-100A. Accordingly, the Siting Council ORDERS Nantucket Electric Company to file its next forecast and supply plan on July 1, 1993. The Siting Council further ORDERS Nantucket to file on June 1, 1992 a brief informational update regarding trends in demand, the status of the Company's C&LM programs and the status of the Company's efforts to obtain new supplies.

Sue Nord

Sue Nord
Hearing Officer

Dated this 17th day of May, 1991

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of May 17, 1991 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Paul W. Gromer (Commissioner of Energy Resources); Penelope Wells (for Gloria Larson, Secretary of Consumer Affairs and Business Regulation); Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Joseph Faherty (Public Labor Member); Mindy Lubber (Public Environmental Member); and Michael Ruane (Public Electricity Member).

Paul W. Gromer
Chairperson

Dated this 17th day of May, 1991

4410H

TABLE 1

NANTUCKET ELECTRIC COMPANY
Base Case Forecast of Annual Sales and Peak Demand[a]
1988-2008

Year	Annual Energy Sales (MWH)	Summer Peak (MW)	Winter Peak (MW)
1988	82,324	19.7	21.0
1989	84,158	19.6	21.0
1990	85,997	19.6	21.4
1991	88,645	20.0	22.8
1992	91,298	20.4	24.1
1993	93,956	20.9	24.1
1994	96,621	21.3	25.3
1995	99,293	21.7	26.5
1996	101,797	22.1	27.8
1997	104,309	22.4	29.2
1998	106,832	22.8	30.5
1999	109,365	23.1	31.9
2000	111,909	23.5	33.2
2001	114,146	23.7	34.7
2002	116,397	24.0	36.1
2003	118,661	24.3	37.6
2004	120,940	24.5	39.1
2005	123,234	24.8	40.5
2006	125,657	25.1	42.2
2007	128,098	25.3	44.0
2008	130,557	25.6	45.7

Notes:

a. Unadjusted for Company-sponsored C&LM

Source: Exh. NAN-1, Table 1-1, Chapter 3, Appendix A

TABLE 2

NANTUCKET ELECTRIC COMPANY
Base Case Forecast of Energy Sales By Customer Class[a]
1988-2008
(MWH)

Year	Residential	Commercial	Streetlighting
1988	57,172	24,854	298
1989	58,680	25,180	298
1990	60,193	25,505	298
1991	62,023	26,324	298
1992	63,858	27,142	298
1993	65,698	27,960	298
1994	67,545	28,778	298
1995	67,399	29,597	298
1996	71,053	30,445	298
1998	74,391	32,143	298
1999	76,075	32,992	298
2000	77,771	33,840	298
2001	79,168	34,680	298
2002	80,579	35,519	298
2003	82,004	36,359	298
2004	83,443	37,198	298
2005	84,898	38,038	298
2006	86,473	38,886	298
2007	88,066	39,734	298
2008	89,677	40,582	298

Notes:

a. Unadjusted for Company-sponsored C&LM

Source: Exh. NAN-1, Table 1-1, Chapter 3, Appendix A

TABLE 3
NANTUCKET ELECTRIC COMPANY
Short-Run Base Case Supply Adequacy

Year	Winter Peak Forecast[a] (MW)	Total Capacity[b] (MW)	Reserve Margin	Contingency Surpl/(Def) (MW)
1991	22.5	30.6	36.0%	.90
1992	23.5	30.6	30.2%	(0.42)
1993	23.1	30.6	32.5%	0.11
1994	24.0	31.3	30.1%	(0.38)

<u>Notes</u>:
a. Adjusted for Company-sponsored C&LM.
b. Excludes Units 2 and 3. Assumes Units 10 and 11 are repermitted as incremental units. Also assumes 0.7 MW of customer generation becomes available as firm supply in 1994. See Section III.C.2.b, above.

<u>Sources</u>: Exhs. HO-S-32, HO-S-34, HO-4, NAN-1, p. 5-13, Chapter 3, Appendix A, Table 1-2; Tr. 2, p. 43.

TABLE 4
NANTUCKET ELECTRIC COMPANY
Short-Run Contingency Analyses

<u>High Peak Load Growth Contingency</u>

Year	Winter Peak Forecast[a] (MW)	Total Capacity[b] (MW)	Reserve Margin	Contingency Surpl/(Def) (MW)
1991	23.1	30.6	32.5%	.11
1992	24.4	30.6	25.4%	(1.61)
1993	24.1	30.6	27.0%	(1.21)
1994	25.2	31.3	24.2%	(1.96)

<u>Inability to Repermit Units 10 and 11 Contingency</u>

Year	Winter Peak Forecast[a] (MW)	Total Capacity[c] (MW)	Reserve Margin	Contingency Surpl/(Def) (MW)
1991	22.5	30.35	34.9%	.65
1992	23.5	30.35	29.1%	(0.67)
1993	23.1	30.35	31.4%	(0.14)
1994	24.0	31.05	29.4%	(0.63)

<u>Notes</u>:
a. Adjusted for Company-sponsored C&LM.
b. Excludes Units 2 and 3. Assumes Units 10 and 11 are repermitted as incremental units. Also assumes 0.7 MW of customer generation becomes available as firm supply in 1994. See Section III.C.2.b, above.
c. Excludes Units 2 and 3. Assumes that current DEP permits for Units 10 and 11 are renewed, and therefore that these units are available for backup service. Also assumes 0.7 MW of customer generation becomes available as firm supply in 1994. See Sections III.C.2.b and III.C.2.c, above.

<u>Sources</u>: Exhs. HO-S-32, HO-S-34, HO-4, NAN-1, p. 5-13, 5-19 to 5-21, Chapter 3, Appendix A, Table 1-2; Tr. 2, p. 43.

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of New England Power Company to Construct a 115 Kilovolt Electric Transmission Line	)	EFSC 89-24A

FINAL DECISION

Sue Nord
Hearing Officer
May 17, 1991

On the Decision:

Phyllis Brawarsky
William Febiger

APPEARANCES: Kathryn J. Reid, Esq.
Thomas G. Robinson, Esq.
New England Power Company
25 Research Drive
Westborough, MA 05182
FOR: New England Power Company
Petitioner

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The Energy Facilities Siting Council hereby APPROVES the petition of the New England Power Company to construct a 5.7-mile 115 kilovolt transmission line, in conjunction with appropriate switching adjustments to the 115 kV system, along the primary route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Massachusetts Electric Company ("MECo") and New England Power Company ("NEPCo" or "the Company") are subsidiaries of the New England Electric System. MECo's service territory includes most of central Massachusetts, and many other communities in diverse locations around the state. New England Electric System, 18 DOMSC 229 (1989) ("1989 NEES Decision"). NEPCo supplies almost all of the electricity distributed by MECo. Id., p. 230.

After reviewing MECo and NEPCo's most recent forecast filing, the Energy Facilities Siting Council ("Siting Council") approved MECo's demand forecast and NEPCo's supply plan. Id., p. 372.

NEPCo has proposed to construct a 5.7-mile 115 kilovolt ("kV") transmission line consisting of: (1) a new 5.2-mile 115 kV electric transmission line from a tap on the existing 115 kV Y151 line, in the Town of Tewksbury, to the existing South Broadway substation in the City of Lawrence ("South Broadway line"); and (2) a new 0.5-mile 115 kV transmission line from a tap on the new South Broadway line to the existing West Andover substation, both in the Town of Andover ("West Andover tap line") (Exh. NEP-6, p. 2-4). For its primary route, NEPCo proposes to place the new transmission line within existing NEPCo-owned electric transmission line rights-of-way ("ROW") in the Towns of Tewksbury and Andover and the City of Lawrence for its entire length ("primary route") (id., p. 2-5). NEPCo identified a 5.5-mile alternative route that includes a 3.3-mile segment from Methuen Junction in the Town of Methuen to the

South Broadway substation which is parallel, for the most part, to Boston and Maine ("B&M") railroad tracks, and a 2.2-mile segment common to the primary route extending from the South Broadway substation to the West Andover substation ("alternative route") (id.).

In addition to the proposed 115 kV transmission line, NEPCo has proposed to install a second 115/23 kV transformer at the South Broadway substation and a second 115/34.5/13.8 kV transformer at the West Andover substation (id., p. 2-4).

B. Procedural History

On April 21, 1989, NEPCo filed with the Siting Council its petition to construct a 5.7-mile 115 kV electric transmission line and related facilities as described herein. On October 10, 1989, the Siting Council conducted a joint public hearing with the Department of Public Utilities in the City of Lawrence. In accordance with the direction of the Hearing Officer, NEPCo provided notice of public hearing and adjudication.

On October 23, 1989, J. Makowski Associates submitted a Late Filed Petition to Intervene. On October 26, 1989, the Chairman of the Andover Planning Board filed a written request to participate as an interested person. On November 3, 1989, J. Makowski Associates filed a Motion to Amend a Late Filed Petition to Intervene, in which it requested to amend its original petition from a petition to intervene to a petition to participate as an interested person. The Hearing Officer granted the requests to participate as an interested person of the Chairman of the Andover Planning Board and J. Makowski Associates on November 13, 1989.

The Siting Council conducted evidentiary hearings on July 23, 25, and 26, 1990. NEPCo presented seven witnesses: Donald K. Ellsworth, distribution planning engineer; Robert H. Snow, manager of transmission and supply planning; Rufin VanBossuyt, system forester; John F. Vance, manager of transmission engineering; David L. Therrien, supervisor of licenses and permits in the environmental affairs department; Gordon E. Marquis, senior environmental analyst; and Werner Doehner, project engineer in the electrical stations engineering department.

The Hearing Officer entered 135 exhibits into the record, largely comprised of NEPCO's responses to information and record requests. Nine exhibits of NEPCo also were entered into the record.

NEPCo filed its brief on September 10, 1990. The Siting Council issued supplemental information requests on August 24, 1990 and November 15, 1990. The Company completed its responses to the supplemental information requests on February 25, 1991.

C. Jurisdiction

The Company's petition is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, sec. 69I, which requires electric companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.

The Company's proposal to construct a 5.2-mile 115 kV electric transmission line and a 0.5-mile 115 kV tap line connected to the 5.2-mile line falls squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G. That section states, in part, that a facility is:

> (2) any new electric transmission line having a design rating of sixty-nine kilovolts or more and which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

The Company also proposes to install new 115/23 kV and 115/34.5/13.8 kV transformers at the South Broadway and West Andover substations, respectively. The third definition of facility set forth in G.L. c. 164, sec. 69G is pertinent in determining whether the transformers are jurisdictional facilities. In that third definition a facility is defined as:

> (3) any ancillary structure including fuel storage facilities which is an integrated part of the operation of any electric generating unit or transmission line which is a facility.

In Commonwealth Electric Company, 17 DOMSC 249, 263 (1988) ("1988 ComElectric Decision"), the Siting Council established a two-part standard for determining whether a structure is a facility under the third definition of facility set forth in G.L. c. 164, sec. 69G. In that case the Siting Council determined that a structure is a facility if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility.

With regard to the first part, the proposed transformers at the South Broadway and West Andover substations are clearly subordinate to the proposed transmission line.

With regard to the second part, the Company asserted that the proposed second 115/23 kV transformer at the South Broadway substation would provide a new power source to the low voltage system in the Lawrence service area (Tr. 1, pp. 154-155). As such, the transformer would increase the power flow capacity and provide a firm transformer capability at the South Broadway substation (Exh. HO-RR-9). By enhancing the size and reliability of the power flow capacity through the South Broadway substation, the transformer would help ensure a balanced supply among the three major substations serving the Lawrence service area (Exh. NEP-2, p. 9). Thus, the proposed second South Broadway transformer would provide benefits to the system irrespective of the jurisdictional facilities.

Additionally, the Company asserted that the proposed 115/34.5/13.8 kV transformer could be installed to provide back-up supply to the 34.5 kV system in the event of the failure of the existing transformer (Exh. HO-N-44). The proposed West Andover transformer would therefore provide benefits to the system irrespective of the jurisdictional facilities.

Accordingly, pursuant to the definition of facility set forth in the 1988 ComElectric Decision, the Siting Council finds that the proposed 115/23kV transformer at the South Broadway substation and the proposed 115/34.5/13.8 kV transformer at the West Andover substation are not jurisdictional facilities.

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section II.A, below). Next, the Siting Council requires the applicant to establish that its project is superior to alternative approaches in terms of cost, environmental impact, reliability and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Council requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, and that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply (see Section III, below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources[1] to meet reliability or economic efficiency objectives. The Siting Council must therefore find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Council has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Bay State Gas Company, EFSC 89-13, pp. 10-19 (1990) ("1990 Bay State Decision"); MASSPOWER, Inc., 20 DOMSC 301, 311-336 ("MASSPOWER"); Berkshire Gas Company, 20 DOMSC 109, 123-132 (1990) ("1990 Berkshire Decision (Phase II)"); Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 9-17 (1989) ("BECo/MWRA"); Massachusetts Electric Company and

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1/ In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management.

New England Power Company, 18 DOMSC 383, 393-403 (1989) ("1989 MECo Decision"); Braintree Electric Light Department, 18 DOMSC 1, 23-27 (1988) ("1988 Braintree Decision"); Altresco-Pittsfield, Inc., 17 DOMSC 351, 360-369 (1988) ("Altresco-Pittsfield"); 1988 ComElectric Decision, 17 DOMSC at 266-279; Boston Gas Company, 17 DOMSC 155, 162-167 (1988) ("1988 Boston Gas Decision"); Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987) ("NEA"); Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986) ("1986 CELCo Decision"); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"); New England Electric System, 2 DOMSC 1, 9 (1977).

With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988) ("1988 Middleborough Decision"); Hingham Municipal Lighting Plant, 14 DOMSC 7, 14-18 (1986) ("1986 Hingham Decision"); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982) ("1982 Taunton Decision"); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981) ("1981 ComElectric Decision"); Middleborough Gas and Electric Department, 3 DOMSC 98, 100-101 (1979) ("1979 Middleborough Decision"); Holyoke Gas and Electric Department, 3 DOMSC 1, 4-7 (1978) ("1978 Holyoke Decision"); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

2. Description of the Existing System

MECo's service territory is divided into twenty geographic Power Supply Areas ("PSA") that are demographically similar (Exh. NEP-2, p. 5). The Merrimack PSA is comprised of three service areas: Lawrence, Lowell and Haverhill (Exh. HO-RR-2, p. 2). The Lawrence service area ("Lawrence Area"), in turn, is comprised of the Towns of Methuen, Andover, and North Andover and the City of Lawrence (Exh. NEP-6, pp. 2-1, 2-2).

The Lawrence Area is fed by several 115 kV transmission lines whose major sources are transmission substations in Tewksbury and Saugus, and the generating station at Salem Harbor (id., p. 2-1).

The Lawrence Area subtransmission voltage is predominately 23 kV (id.). Three major substations -- South Broadway, West Methuen, and Ward Hill -- step down the voltage from the 115 kV transmission level to the 23 kV subtransmission level (id.). The South Broadway substation, located in the southern part of the City of Lawrence, presently includes one 50 megavolt-ampere ("MVA") transformer and is supplied from one radial 115 kV line (Exh. NEP-2, p. 4). The West Methuen substation, located northwest of the City of Lawrence, includes two 50 MVA transformers and is supplied from two 115 kV lines (Exh. NEP-2, p. 3). The Ward Hill substation is located to the northeast of the City of Lawrence at the junction of three 115 kV lines and includes two 80 MVA transformer banks (Exh. NEP-2, p. 3).

The 23 kV subtransmission system extends throughout the Lawrence Area and supplies several distribution substations which step down the voltage level from 23 kV to the two primary distribution voltages, 13.2 kV and 4.16 kV (Exh. NEP-6, pp. 1-1, 2-1).

Additionally, two distribution substations in the Lawrence Area are supplied directly from the 115 kV transmission system: the West Andover substation, where the distribution system operates at 34.5 kV and 13.2 kV, and the East Methuen substation, where it operates at 13.2 kV (id., p. 2-1).

Figure 1 shows the location of the major electrical facilities in the Lawrence Area.

3. Reliability of Supply

The Company asserted that the need for the proposed project is based upon (1) lack of firm supply for the Lawrence Area as a whole under forecasted summer peak loads, and (2) lack of firm supply for the 34.5 kV load currently supplied by the West Andover substation (id., pp. 2-2, 2-3). The Company's system design criteria define a supply as firm "if a single contingency will not cause a loss of load for longer than the time required for automatic switching" (Exh. NEP-2, attachment RHS-9, sec. 2.5).[2]

In order to evaluate whether there is a need for additional energy resources on reliability grounds, the Company determines whether existing and projected loads, under certain contingencies, meet the system reliability criteria. In this section, the Siting Council first examines the reasonableness of the Company's system reliability criteria. Next the Siting Council evaluates whether the Company's load forecast methodology is reasonable and acceptable. Finally, the Siting Council evaluates (1) whether the Company uses reviewable and appropriate methods for assessing system reliability based on load flow analysis, and (2) whether existing and projected loads, under certain contingencies, exceed the Company's reliability criteria, thereby requiring additional energy resources.

2/ In addition, the system design criteria require the supply system to be designed to preclude equipment loadings above emergency capabilities and to preclude voltage fluctuation beyond acceptable limits which would otherwise damage equipment (id., attachment RHS-9, sec. 2). (The Company indicated that acceptable limits on voltage fluctuation are ten percent for normal and 15 percent for emergency conditions (id., attachment RHS-9, section 2.4)).

a. Reliability Criteria

In regard to reliability objectives, the Company provided service reliability and system design criteria applicable to the classes of transmission and distribution found in the proposed project area (Exh. NEP-2, attachment RHS-9, sec. 2.5) The Company stated that in order to meet its system design criteria for firm supply, in the event of the outage of any one major facility, the system must be capable of (1) serving the customer load within a time period no longer than that required for automatic switching, and (2) continuing to serve the customer load for at least as long as it takes to repair the facility (id., Exh. NEP-2, p. 8).

The Company's system design criteria require firm supply in cases where the non-firm peak load in a contiguous distribution area equals or exceeds 30 MW (id.). For contiguous distribution areas with non-firm peak loads below 30 MW but above 20 MW, the Company's system design criteria require that a three-hour outage once in three years, or a 24-hour outage once in ten years, is not to be exceeded (id.).

The Company justified its reliability criteria based on comparison with industry practices and the Company's own experience with its established standards over a period of years (Tr. 1, pp. 123-124). The Company indicated that its 30 MW threshold for firm power is comparable to the reliability standards set by other utilities serving suburban and rural areas within New England,[3] and that it would consider a lower power level at which to require firm supply if a poor history of reliability gave rise to customer dissatisfaction (Tr. 1, p. 124).

3/ The Company indicated that its 30 MW threshold for firm supply is comparable to the standards of the following New England utilities with predominantly suburban and rural service areas: Northeast Utilities, Public Service of New Hampshire, Central Maine Power, and Eastern Utilities Associates (Tr. 1, pp. 125-126).

The Siting Council consistently has found that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain adequate system reliability. 1988 Middleborough Decision, 17 DOMSC at 206-219; 1986 Hingham Decision, 14 DOMSC at 15; 1985 BECo Decision, 13 DOMSC at 70-73; 1982 Taunton Decision, 8 DOMSC at 154; 1981 ComElectric Decision, 6 DOMSC at 43-44; Middleborough Gas and Electric Department, 3 DOMSC 98, 101; 1978 Holyoke Decision, 3 DOMSC at 7.

The record in this case does not address in detail the factors that support the specific load levels reflected in the Company's reliability standards. However, the approach of establishing a threshold for firm supply based on the size of contiguous load, with a lower threshold where outage experience gives rise to customer dissatisfaction, is reasonable. Further, the record suggests that the Company's standards for reliability are comparable to the reliability standards of utilities serving areas of similar density. Accordingly, the Siting Council finds that, for the purposes of this review, the Company's reliability criteria are reasonable.

b. Load Forecasts

i. Description

The Company provided load forecasts for the Merrimack PSA, the Lawrence Area, and distribution substations within the Lawrence Area (Exhs. NEP-2, attachment RHS-4, HO-N-6, HO-N-23d, HO-N-37).

The Company indicated that it develops PSA load forecasts from the MECo system forecast based upon historical trends within the PSA that are tracked by measuring devices throughout the system, as well as economic and demographic forecasts for the PSA (Tr. 1, pp. 114-115). The Company further explained that the individual PSA forecasts add up to the total MECo system forecast (Exh. HO-N-15).

The Company indicated that service area load forecasts are subdivisions of PSA load forecasts (Tr. 1, p. 36). The Company stated that the forecasted total PSA load is allocated to service area loads by engineering staff in divisional offices based on the historical peak load at distribution substations at the time of the PSA peak load,[4] and distribution studies (Exhs. HO-N-16, NEP-2, attachment RHS-9, sec. 2.1; Tr. 1, pp. 36-37).

Within the area forecasts, the Company forecasts load growth for individual distribution substations (Exhs. HO-N-6, HO-N-7, HO-N-23c, NO-N-24, HO-N-37c). Although the Company did not present a quantitative method for projection of load growth at individual substations, the Company stated that,

> [i]t is more economical to place new growth on 13 kV feeders rather than increase 4 kV capacity. Therefore, these 13 kV substations will grow fast because they will pick up new load...together with the load converted from 4 kV to 13 kV...to keep the 4 kV feeders and stations within their firm capability (Exh. HO-N-24).

The Company stated that the load growth forecast for the Merrimack PSA is developed by the Company's Demand Forecasting Department while that for the Lawrence Area is developed by the Distribution Engineering Department in the Company's North

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4/ The Company indicated that the time of a substation's peak load is dependent upon its mix of commercial, industrial and residential load, and that substations within an area do not necessarily peak at the same time (Exh. HO-N-25; Tr. 1, pp. 36-37). The Company allocates the peak load at the time of the PSA peak to the various distribution substations (Exh. HO-N-16). For substations with electronic monitoring devices, the Company obtains records of actual load, at the peak hour of the PSA (id.). For those substations without electronic meters, the Company estimates the load at the peak hour of the PSA based on the substation's mix of commercial, industrial and residential load relative to the mix within the PSA (Exh. HO-N-16; Tr. 1, pp. 39-40). The sum of the actual and estimated substation loads at any one given hour is termed diversified load and is equal to the PSA peak load (Exh. HO-N-25; Tr. 1, p. 36).

Andover office (Exhs. NEP-2, p. 5, HO-N-17). PSA forecasts are updated annually, while area studies are updated annually only for those areas undergoing distribution studies (Tr. 1, pp. 37-38). The Company indicated that the Lawrence Area forecast has been updated annually during the last two or three years (id., p. 38).

The Company provided the August 1989 base case and high case[5] forecast for the Merrimack PSA and for the Lawrence Area (Exh. NEP-2, attachment RHS-4). Additionally, the Company provided base case and high case forecasts for the Merrimack PSA and a Lawrence Area forecast that correspond to a January 1991 system-wide forecast update (Exh. HO-E-37).[6] The Company also provided corresponding 1989 and 1991 forecasts of individual Lawrence Area distribution substation loads (Exhs. HO-N-23d, HO-N-37c).

Table 1 shows: (1) the actual 1989 summer peak load for the Merrimack PSA; (2) the actual 1989 and 1990 diversified summer peak load for the Lawrence Area; (3) the Company's 1989 base case forecast of summer peak load for 1989 through 1997 for the Merrimack PSA and the Lawrence Area; (4) the Company's 1991 high case and base case forecast update of summer peak load for 1990 through 1997 for the Merrimack PSA; and (5) the Company's 1991 forecast update of diversified summer peak load for the Lawrence Area for 1990 through 1995 (Exhs. NEP-2, attachment RHS-4; HO-RR-2; HO-N-37b,c).

5/ The Company indicated that the base case forecast is a long-range forecast that accounts for the effects of conservation and load management and that the high case forecast is a high-growth, short-range forecast that accounts for the possibility that conservation and load management may not be effective (Exh. NEP-2, p. 6).

6/ The Company indicated that the 1991 base case, which reflects current economic outlook information and higher fuel prices, is appropriate for long range planning (Exh. HO-N-37b). The Company further indicated that the high case reflects extreme weather at the time of peak and is appropriate for short and intermediate term planning since it considers the risk of higher than expected growth in the small geographic areas encompassed by the PSA's (id.).

The Company indicated that the 1989 base case forecast was utilized in its contingency analysis (Tr. 1, p. 130) (see Section II.A.3.c, below).

In explaining its projection of load growth on the 34.5 kV feeders supplied by the West Andover substation, the Company stated that it intends to utilize the 34.5 kV feeders to serve the still developing Andover Tech Center ("Tech Center") and to absorb growth along the fully loaded 13.2 kV feeders (Exh. HO-N-7, NEP-1, pp. 6-7). However, the Company offered varying projections of load growth on the 34.5 kV feeders, from 4.3 percent per year to ten percent per year (id., HO-N-23c, HO-N-37c).[7] In addition, the Company indicated that an existing Tech Center customer plans to erect a facility within the Tech Center which would add a 10 MW load (HO-N-37c).[8] However, the Company did not provide any verification of this anticipated new 10 MW load (id.).

Table 2 shows the actual 1989 and 1990 diversified peak load and the Company's 1989 base forecast and 1991 forecast update of summer peak load for the 13.2 kV and 34.5 kV feeders supplied by the West Andover substation (Exhs. NEP-1, p.4, HO-RR-4, HO-N-6, HO-N-23d, HO-N-37c). (The 1989 peak load on the 34.5 kV feeders was measured electronically and was coincident with the Merrimack PSA summer peak (Exh. HO-RR-4)).

7/ The Company stated that it estimated load growth of 10 percent per year on the 34.5 kV feeders (Exh. NEP-1, p. 7). However, based on the Company's 1989 forecast, the Company projected 34.4 percent load growth from 1989 to 1997 or an average yearly increase of 4.3 percent (Exh. HO-23d). Further, in the Company's 1991 forecast update, the Company projects 32.5 percent load growth from 1990 to 1995, or an average yearly increase of 4.7 percent (Exh. Exh. NO-N-37c).

8/ The Company indicated that this anticipated new 10 MW load is not included in its 1991 Lawrence Area forecast update (Exh. HO-N-37c).

ii. Analysis

In presenting its PSA forecast, the Company adequately explained its derivation of historic trends in order to prorate the system forecast into separate PSA forecasts. The Company also summarized the other components of its PSA forecasts, i.e., economic and demographic factors specific to the PSA. However, the Company did not provide a systematic methodology for: (1) the integration of PSA-specific economic and demographic information into PSA forecasts, and (2) the adjustment of the PSA forecasts to conform to the system forecast. In particular, the Company relied upon judgmental rather than quantitative techniques to account for PSA load growth.

Likewise, for area forecasts, the Company adequately described the compilation of historical data at distribution substations but did not adequately explain its methodology for forecasting load growth within the area. Specifically, the Company did not provide a systematic methodology for: (1) the development of distribution studies which would indicate substation growth; (2) the integration of results of distribution studies into area forecasts; and (3) the adjustment of area forecasts to conform to PSA forecasts. Additionally, although the Company accounted for variations in substation load growth due to differing feeder voltages, the Company did not provide a quantitative methodology for the projection of future load at individual substations. Finally, the Company offered conflicting estimates of growth on the West Andover 34.5 kV feeders.

In sum, the Company relied on judgmental rather than quantitative techniques to account for area load growth and substation load growth. The Company also relied on judgmental rather than quantitative techniques to account for differences among the forecasts for the individual areas within a PSA and between each such individual forecast and that for the PSA as a whole.

In general, companies should use quantitative techniques, where sufficient data is available, or other systematic techniques to allocate system-wide growth to service areas and document pertinent assumptions in order to support the allocation of system-wide growth to service areas. In addition, Companies should use quantitative techniques, where sufficient data is available, or other systematic techniques to forecast load growth at individual substations and document pertinent assumptions in order to suport the allocation of system-wide growth to individual substations.

In previous facility reviews, the Siting Council has accepted a Company's load forecast for a division of its territory based on quantitative methods for forecasting divisional peak loads and allocating divisional peak loads to the bulk substation level (1988 ComElectric Decision, 17 DOMSC at 272-273) and has accepted a Company's projection of load growth at individual substations based on documentation of known, new projects within the areas served by the substations (1988 Braintree Decision, 18 DOMSC at 22).

In this case, as stated above, the Company's methodology for: (1) allocating the system forecast to PSA forecasts; (2) allocating PSA forecasts to area forecasts; and (3) forecasting load growth at individual substations is not based on quantitative or other systematic methods. However, because the Company has explained its judgments, its methodology is marginally reviewable. Further, the Company demonstrated that, in those portions of its service area where a need for additional energy resources now exists or will exist in the near future, it reviews and revises its forecasts regularly on the basis of updated information. Accordingly, for the purposes of this review, the Siting Council finds that the Company's methodology is reasonable and acceptable.

In future facility reviews, where a company projects load growth for a portion of its service territory, however, the Siting Council will require companies to use quantitative techniques, where sufficient data is available, or other systematic techniques, and to document all pertinent assumptions to support the allocation of system-wide growth to service areas and to individual substations within the service areas.

c. Contingency Analysis

The Company analyzed the reliability of supply to the Lawrence Area based on the single contingency outage of each of the five 115 kV transmission lines supplying the Lawrence Area and each of the transformers at the five Lawrence Area supply substations (Exh. HO-N-12). The Company provided a set of load flow analyses, based on the 1989 base case area forecast of 1990 and 1992 peak loads, to simulate system operation under normal conditions and with each major component out of service (id.; Tr. 1, p. 130). The proposed facilities were not included in this set of load flow analyses (Exh. HO-N-12). As the basis for assessing system adequacy, the Company examined load flow diagrams to identify any system problems such as equipment loading above designated ratings for normal and emergency conditions and voltage below designated minimum levels (Exh. HO-N-28).

The Company provided normal and emergency MVA capabilities for summer and winter[9] for: (1) transformers at the five major substations; (2) 115 kV transmission lines in the Lawrence Area; and (3) 23 kV transmission lines in the Lawrence Area (Exh. NEP-6, Tables 2-1, 2-2, 2-3).

The Company's analysis identified contingencies in which its existing system fails to meet its reliability criteria in the Lawrence Area and at the West Andover substation (Exhs. HO-N-12c, HO-N-12j, NEP-6, Tables 2-1, 2-2, 2-3).

i. Lawrence Area Load

The Company asserted that, with an area load level of approximately 300 MW,[10] load flow analyses identify two

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9/ Emergency capabilities of electrical equipment are lower in the summer than in other seasons due to higher ambient temperatures in the summer (Exh. NEP-2, p. 5). Therefore, for the purposes of this analysis, the Siting Council uses the emergency summer capabilities.

10/ Based on the 1989 base case forecast and the 1991 forecast update, the Lawrence Area peak load will reach 300 MW in 1992 (Exhs. NEP-2, attachment RHS-4, HO-N-37c).

contingencies on the 115 kV network in the Lawrence Area that would load one West Methuen transformer in excess of its emergency capability, thereby exceeding the Company's reliability criteria (Exh. NEP-2, p. 7). These contingencies are (1) the loss of one 115/23 kV transformer at the West Methuen substation, and (2) an outage of the West Methuen to Ward Hill 115 kV transmission line (G133 line) (id.; Exh. NEP-6, Table 2-2).

The Company also asserted that a third contingency, an outage of the Tewksbury to West Methuen 115 kV transmission line (Y151 line), would load the South Broadway transformer and the South Broadway to West Methuen 23 kV subtransmission line (2355 line) above their emergency summer capabilities under forecasted 1990 summer peak load (Exhs. NEP-2, p. 8, NEP-6, Table 2-2).

With regard to the first contingency relative to the West Methuen transformer, the Company identified the summer emergency capabilities of transformers #1 and #2 at the West Methuen substation as 62 MVA and 67 MVA, respectively (Exh. NEP-6, Table 2-2).[11] The Company provided load flow analyses of the outage of one West Methuen transformer which show that under the forecasted 1990 area peak load of 278 MW, the remaining West Methuen transformer will be loaded at approximately 61.6 MVA,[12] which is just within its emergency summer

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11/ West Methuen transformer #1 and transformer #2 are not distinguished in the load flow analyses and, in each analysis, the substation load is evenly divided between the two transformers (Exhs. HO-N-12, HO-N-29, NEP-2, attachments RHS-6, 7, 8, 10, 11, 12). Transformer capabilities therefore are compared to the lower 62 MVA rating for purposes of this discussion.

12/ In its load flow analyses, the Company provided equipment loading expressed in MW and megavars ("MVAR") (Exh. HO-N-28). In its petition, the Company provided equipment capabilities expressed in MVA (Exh. NEP-6, Tables 2-1, 2-2, 2-3). The Company indicated that conversion of the loading expressed in MW and MVAR to a loading expressed in MVA would be approximately equal to the measure of MW (Exh. HO-N-28).

capability, and under a forecasted 1992 area peak load of approximately 300 MW, the remaining West Methuen transformer will be loaded at approximately 63.8 MVA, which is above its summer emergency capability (Exhs. HO-N-12c, NEP-2, attachment RHS-4, NEP-6, Table 2-1).[13]

With regard to the second contingency relative to the West Methuen transformer, the Company presented a load flow analysis of an outage of the 115 kV transmission line from West Methuen to Ward Hill (G133 line) under 1992 area peak load conditions (Exh. HO-N-12 a, i). This analysis indicates that the loading on each West Methuen transformer would increase from its normal loading of approximately 41.8 MVA to approximately 55.0 MVA, which is within the emergency capability of each transformer (id., Exh. NEP-6, Table 2-1).[14]

In regard to the contingency relative to the South Broadway transformer and the 23 kV 2355 line (South Broadway to West Methuen), the Company provided load flow analyses of the outage of the Tewksbury to West Methuen 115 kV transmission line (Y151 line) (Exh. HO-N-12j). The load flow analysis of the outage of the Y151 line indicates overloads on both the South Broadway transformer and the 23 kV 2355 line (South Broadway to West Methuen) under 1990 and 1992 forecasted area peak loads (id., Exh. NEP-6, Table 2-3).

13/ The Company indicated that an additional load of 6.1 MW is anticipated from the proposed Rockingham Mall, which the Company assumes will be complete by 1992 and which will be supplied through the West Methuen substation. With this additional load and the loss of a West Methuen transformer, the loading on the remaining transformer would increase to approximately 69.9 MVA under 1992 area peak load conditions (Tr. 2, p. 22; Exh. HO-RR-10).

14/ If the 6.1 MW Rockingham Mall load were allocated equally to each West Methuen transformer under this contingency, the maximum loading on each West Methuen transformer still would remain within emergency capabilities (Exh. HO-N-12i; Exh. NEP-6, Table 2-1).

The Company's analysis, under this contingency, demonstrates that, for 1990, the South Broadway transformer is loaded at approximately 84.4 MVA, which is above its emergency summer capability of 79 MVA and the 2355 line is loaded at approximately 42 MVA, which is above its emergency summer capability of 41 MVA (id.). The Company's analysis further demonstrates that, for 1992, the loading on the South Broadway transformer is increased to approximately 89.0 MVA, and the loading on the 2355 line is increased to approximately 43.7 MVA, both in excess of their respective emergency summer capabilities (Exh. HO-N-12j).

However, the Company's load flow analysis under this contingency assumes that the 2355 line is closed (Exh. HO-N-12j).[15] Further load flow analyses of the Y151 line outage contingency indicate that switching adjustments on the 2355 line allow loadings on both the South Broadway transformer and the 2355 line to remain within emergency capacity under 1990 and 1992 forecasted area peak loads (Exhs. HO-N-29, HO-N-12j, NEP-6, Table 2-2, 2-3). Loading on the South Broadway transformer, with the switching adjustment, is approximately 73.9 MVA in 1990 and 77.9 in 1992, which is within its emergency summer capability (Exh. NEP-2, attachments RHS-10 and RHS-11). Similiarly, loading on the 2355 line, with the switching adjustment, is approximately 24 MVA in 1990 and 23.4 MVA in 1992, which is once again within the emergency summer capability of this line (id.).

The Company currently has the ability to manually adjust the switch on the 2355 line (Exh. HO-N-29). The Company stated that it plans to install an automatic circuit breaker on the 2355 line in order to allow switching adjustments which will maintain loading on the South Broadway transformer and the 2355

15/ The Company stated that under normal operating conditions the 2355 line would be closed but that it has the capability to open this line in order to interrupt the load under certain outage contingencies (Tr. 1, pp. 161-162, 167).

line within emergency capabilities in the event of the outage of the Y151 line (Tr. 1, p. 169; Tr. 2, p. 85).[16]

The Company asserted that even with the switching adjustments, the South Broadway transformer would be loaded at close to its capacity under the contingency of the loss of the Y151 line (Tr. 1, p. 169-170). The Company indicated that an increase in load of approximately 6.7 percent would load the South Broadway transformer above its emergency capability of 79 MVA under the contingency of the loss of the Y151 line, even with the 2355 line switching adjustment (id., p. 170). According to the Company's 1991 forecast update of the Lawrence Area diversified load, a 6.7 percent growth in load would occur by 1995 (Exh. HO-N-37c).

In its load flow studies, the Company consistently related its assumptions and conclusions to its reliability criteria. The Siting Council finds that the Company used appropriate and reviewable methods for assessing system reliability based on load flow analysis.

In sum, the Siting Council finds that the Company's load flow analyses demonstrate that, under the first contingency relative to the West Methuen transformer -- the loss of one transformer at the West Methuen substation -- the remaining West Methuen transformer would be loaded in excess of its emergency capability under forecasted 1992 peak load conditions. The Siting Council also finds, however, that the Company's load flow analyses fail to demonstrate that, under the second contingency relative to the West Methuen transformer -- the loss of the G133 transmission line -- equipment would be loaded in excess of emergency capabilities under forecasted 1992 peak load.

Further, we find that, under the contingency relative to

16/ The Company indicated that under current conditions the 2355 line cannot be permanently maintained in an open position (Tr. 1, pp. 162-163). The Company explained that under the contingency of the loss of the existing South Broadway transformer, the 2355 line is the only supply for the 23 kV load (approximately 40 MVA) supplied out of the South Broadway 23 kV bus (id.).

the South Broadway transformer and 2355 line -- the loss of the Y151 line -- the Company's load flow analyses fail to demonstrate that the South Broadway transformer and 2355 line would be loaded in excess of emergency capabilities under forecasted 1992 peak load. However, the Company established that under this contingency, the South Broadway transformer would be loaded in excess of its emergency capability under forecasted 1995 peak load conditions.

Thus, the Company has identified two contingencies -- the loss of one West Methuen transformer and the loss of the Y151 line -- whereby the loss of single major components of the supply system would create transformer loading in excess of emergency capabilities, in violation of the Company's reliability criteria. Accordingly, the Siting Council finds that the supply to the Lawrence Area will not meet the Company's reliability criteria in 1992 in the event of the loss of one 115/23 kV transformer at the West Methuen substation, and will not meet the Company's reliability criteria in 1995 in the event of the loss of the Y151 transmission line.

ii. <u>West Andover Load</u>

The Company stated that the West Andover substation is a distribution substation, which is supplied directly from the 115 kV transmission system via a tap line from the 115 kV L164 transmission line (Exhs. NEP-1, p. 4, NEP-6, p. 2-1). The Company indicated that the distribution system originating at the West Andover substation, operating at 34.5 kV and 13.2 kV, is supplied by one 115/34.5/13.8 kV transformer (Exh. NEP-6, p. 2-1).

The Company stated that the 13.2 kV portion of the substation was constructed in the 1960's and that two 13.2 kV feeders currently serve a total of 1,463 customers (Exh. NEP-1, p. 4). The Company further stated that the 34.5 kV portion of the substation was constructed in 1984 in order to serve the Tech Center, and that, currently, two 34.5 kV feeders serve a total of 354 customers at the Tech Center and at other locations within Andover (id., p. 6, Exh. HO-RR-5).[17]

The Company asserted that the proposed transmission line and tap to the West Andover substation are required in order to provide a firm supply to the 34.5 kV distribution load at the West Andover substation due to projections of increasing load on the two 34.5 kV feeders, and the failure of the Company's mobile spare transformer (Exhs. NEP-6, p. 2-3, NEP-1, pp. 5-6).

In 1980, the Company originally forecasted a Tech Center load of 39.2 MW in 1986 and 44.5 MW in 1990 (Exh. NEP-1, p. 7). Based on this forecast, the Company identified a need for a second transformer at West Andover in 1986 (id.). However, the Company stated that the actual 34.5 kV load has grown at a slower rate than originally projected (id.). The diversified load at the West Andover substation peaked in 1989 at only 31 MW (9.8 MW of 13.2 kV load and 21.2 MW of 34.5 kV load) (id., p. 4; Exh. HO-RR-4). On July 18, 1990, the combined load served by the West Andover substation peaked at 33.5 MW (Exh. HO-N-37c; Tr. 2, p. 81).[18]

As noted above, the Company currently (1) projects annual growth on the 34.5 kV feeders to be between 4.3 percent and

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17/ The Company indicated that, in 1980, it conducted a long-range study comparing detailed plans for the Andover area, including: (1) a plan to establish 34.5 kV distribution at the West Andover substation; (2) an alternative plan to install a larger 115/23 kV transformer at the South Broadway substation with two dedicated 23 kV circuits to the Tech Center; and (3) two alternative plans to expand the 13 kV system (Exh. NEP-1, p. 9). The Company asserted that the plan for establishment of the 34.5 kV distribution system to the Tech Center, which was selected, was advantageous for cost reasons, including: (1) lower initial investment; (2) lower line losses; and (3) the ability to more economically serve an area with high growth rates (id., pp. 9-10; Tr. 1, p. 69).

18/ The Company stated that for the five weekdays of the week of July 16, 1990, the total load (34.5 kV and 13.2 kV feeders) at the West Andover substation was above 32 MW each day (Tr. 2, p. 81).

10 percent; and (2) anticipates an additional 10 MW load in the Tech Center (see Section II.A.3.b.i, above).

The Company asserted that, under its design criteria, it initially was acceptable to establish the 34.5 kV system with a single transformer supply, in that a mobile spare transformer could have been connected to the load in the event the substation transformer failed (Exh. NEP-6, p. 2-3). The Company stated that at the time the 34.5 kV system was established, the Company had a mobile transformer which was portable and ready to be moved, and had an additional backup transformer which could have been taken out of service and moved to provide the Tech Center with 34.5 kV service (id.; Tr. 1, p. 60). However, the Company stated that, currently, the mobile transformer is permanently faulted and the backup transformer is in service elsewhere in place of a failed transformer (Tr. 1, p. 60; Exh. NEP-1, p. 5). Therefore, the Company asserted that in order to meet its reliability criteria, additional facilities are needed under two supply contingencies (Exh. NEP-6, p. 2-3).

The Company analyzed current system back-up supply capabilities under the following contingencies (1) the loss of the 115/34.5/13.8 kV transformer at the West Andover substation, and (2) the loss of the L164 transmission line (Exh. NEP-1, pp. 5-6).

The Company asserted that, in the event of the failure of the 115/34.5/13.8 kV transformer, the entire 34.5 kV load would be out of service (Exh. NEP-1, p. 5). The Company stated that due to the unavailability of a spare transformer, the 34.5 kV load would have no back-up supply (id.). The Company indicated that the 34.5 kV load peaked at 21.2 MW in July 1989 and that, currently, 354 customers would be without service under this contingency (Exhs. HO-RR-4, HO-RR-5). The Company explained, however, that under this contingency the 13.2 kV load would have a backup supply because one 13.2 kV feeder serving 3.8 MW could be transferred to other substation feeders, and the second

13.2 kV feeder serving 6 MW could be shifted to the 1316 XYZ feeder (Tr. 1, pp. 72, 78; Exh. NEP-1, p. 5).[19]

The Company asserted that under the second contingency of the loss of the L164 line: (1) the supply to the 13.2 kV feeders similarly would be backed up by transfer of one feeder serving 3.8 MW to other substation feeders and shifting of the second feeder serving 6.0 MW to the 1316 XYZ line; (2) the remaining capacity of the 1316 XYZ line would be available to backup a portion of the 34.5 kV load; and (3) the portion of the 34.5 kV load not accommodated on the 1316 XYZ line would be out of service until the transmission line was repaired (Tr. 1, pp. 78-80). The Company indicated that the 24-hour rating of the 1316 XYZ feeder is 21 MVA[20] and that the entire capacity of this feeder would be available for backup under this contingency (Tr. 1, pp. 71, 78). Therefore, after the transfer of 6 MW from the 13.2 kV feeder to the 1316 XYZ line, approximately 15 MW of the 34.5 kV load could be backfed through the transformer to the 1316 XYZ feeder (Tr. 1, p. 79).[21] Thus, under this contingency, approximately 6 MW of the 34.5 kV load would not be served until the transmission line was repaired.

In order to address reliability of supply at the West Andover substation under each of the contingencies discussed above, the Company applied its standards for firm supply to existing and projected loads. For contiguous loads of 30 MW the

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19/ The 1989 peak on the two 13.2 kV feeders was 9.8 MW (NEP-1, p. 4)

20/ The normal rating of the 1316 XYZ feeder is 16.7 MVA and the 24-hour rating (the capacity for a maximum of 24 hours) is 21 MVA (Tr. 1, p. 78). The 24-hour rating of the 1316 XYZ feeder was used to determine the amount of 34.5 kV load that can be shifted because in theory the L164 line can be repaired in 24 hours (Tr. 1, p. 79).

21/ The Company noted that the backfeeding of a portion of the 34.5 kV load that can be shifted to the 1316 XYZ circuit requires considerable engineering expertise and would require two to six hours, at a minimum (Tr. 1, pp. 92-93).

Company applied its "30 MW criterion" and for loads below 30 MW but exceeding 20 MW the Company applied its "20 MW criterion."

(A) <u>30 MW Criterion</u>

As noted above, the Company's design criteria specify that firm supply is required if the non-firm peak load in a contiguous area equals or exceeds 30 MW (Exh. NEP-2, attachment RHS-9, sec. 2.5.1). As further noted above, in order to meet the Company's requirement for firm supply, in the event of the outage of any one major facility, the supply system must be capable of (1) serving the customer load within a time period no longer than that required for automatic switching, and (2) continuing to serve the customer load for at least as long as it takes to repair the facility (<u>id.</u>, Exh. NEP-2, p. 8).

In addressing reliability of supply at the West Andover substation, it is unclear from the record whether the Company asserts that the 30 MW criterion is triggered by (1) evaluation of the 34.5 kV load alone, or (2) evaluation of the combined 34.5 kV and 13.2 kV loads.[22] Although the record is unclear in this case, the Siting Council reviews (1) whether the 34.5 kV load alone triggers the 30 MW criterion, and (2) whether the 34.5 kV load combined with the 13.2 kV load triggers said criterion.

In regard to the 34.5 kV load alone, the record indicates that the 1989 peak load on the 34.5 kV feeders was 21.2 MW (Exh. HO-RR-4). The record further indicates that this entire load would be out of service in the event of the loss of the

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<u>22</u>/ The Company's petition and brief focus on the 34.5 kV load alone to support the Company's position that its 30 MW criterion requires additional facilities to provide firm supply at West Andover substation (Exh. NEP-6, pp. 2-4, 2-5, Brief, pp. 6-7). However, the Company's witness, Mr. Ellsworth, stated that the 30 MW criterion is triggered by combining the 34.5 kV load and the portion of the 13.2 kV load that would be shifted to the 1316 XYZ feeder (Tr. 1, p. 95). Mr. Ellsworth also stated that the timing of the need for the proposed facilities depends on when the 34.5 kV load alone was projected to reach 30 MVA (Tr. 1, pp. 90-91).

transformer and that approximately 6 MW of this load would be out of service in the event of the loss of the L164 transmission line. Thus, the loss of the 34.5 kV load alone, under either contingency, does not trigger the 30 MW criterion and, therefore, does not require firm supply.

The Siting Council notes that development of the proposed 10 MW project in the Tech Center would bring the 34.5 kV load to 30 MW in the near future. With this addition, supply to the 34.5 kV load would fail to meet the Company's reliability criteria. However, the Company failed to provide any verification of this anticipated new load.

Based on the foregoing, the Siting Council finds that the Company failed to substatiate that the 30 MW criterion is triggered by the nonfirm 34.5 kV load alone supplied by the West Andover substation.

In regard to the combined 34.5 and 13.2 kV loads supplied by the West Andover substation, the record indicates that the combined load supplied by the substation peaked at 31 MW in 1989 and at 33.6 MW in July 1990 (Exh. NEP-1, p. 4; Tr. 2, p. 81). While the combined 34.5 kV and 13.2 kV peak load exceeds 30 MW, analysis of whether the combined load would exceed the 30 MW criterion for firm peak load involves evaluation of the automatic switching capabilities of the supply to the 13.2 kV feeders. The Company indicated that switching of the load in one minute or less would be considered to be "automatic switching" (Tr. 2, p. 81).

However, based on the record, the automatic switching capability of the supply to the 13.2 kV feeders is not clear. The Company indicated that the transfer of one 13.2 kV feeder to another substation is "slow firm," requiring one to two hours and that shifting of the second 13.2 kV feeder to the 1316 XYZ circuit would require more time than shifting the first feeder (Tr. 1, p. 95). Additionally, the Company acknowledged that (1) some of the 13.2 kV load could be backed up on an automatic basis, and (2) the supply to both 13.2 kV feeders will transfer automatically (Tr. 2, p. 81; Exh. NEP-1, pp. 4-5).

The Siting Council finds that the Company has offered conflicting testimony regarding the automatic switching capability of the supply to the 13.2 kV feeders. Accordingly, the Siting Council finds that the Company has failed to establish that the 30 MW criterion is triggered by the nonfirm 34.5 kV and 13.2kV loads supplied by the West Andover substation.[23]

(B) 20 MW Criterion

For loads that exceed 20 MW, the Company's reliability criterion indicates that the "supply system should be designed so that a three-hour outage once in three years, or a 24-hour outage once in ten years are not exceeded" (Exh. NEP-2, attachment RHS-9, sec. 2.5.1). The record demonstrates that the Company's reliability criteria includes guidelines regarding the duration of different types of contingencies (id., sec. 2.5.2). The record further demonstrates that, in regard to transformer failure, the reliability criteria states that "several weeks or months may be required to repair a failed transformer" and "mobile transformer capacity can be used in most substations, and can be connected within 24 hours to replace a failed transformer" (id.).

The Company asserted that changes in temporary backup capabilities have affected reliability of supply at the West Andover substation and that the proposed facilities are necessary in order for the Company to meet its standards for loads that exceed 20 MW but are less than 30 MW (Tr. 1, pp. 53, 64). The Company stated that due to the absence of a spare transformer, the 34.5 kV load, now above 20 MW, would be subject to an outage lasting more than 24 hours in the event of failure of the existing 115/34.5/13.8 kV transformer at the West Andover

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23/ In reviewing the application of the 30 MW criterion relative to the 34.5 kV load alone and to the combined 34.5 kV and 13.2 kV load, the Siting Council does not addresss the issue of whether it is appropriate, generally, to apply reliability criteria to one portion of a substation load or to the entire substation load.

substation and would therefore fail to meet the Company's reliability criteria (id.).[24,25]

The Company stated that it is its philosophy to have a mobile transformer available (Tr. 1, p. 65). The Company indicated that it plans to replace the failed mobile transformer, that specifications for a new mobile transformer are currently being prepared, and that it expects to have the mobile transformer on hand by the first quarter of 1992 (Exh. HO-N-43).

Due to the current lack of a mobile transformer, the entire 34.5 kV load would be out of service in the event the existing 115/34.5/13.8 kV transformer failed at the West Andover substation until the transformer was repaired (id., p. 81). Thus, under this contingency, it is likely that the 34.5 kV load, which is greater than 20 MW, would be out of service for more than 24 hours.[26]

Based on the Company's record of supply system disturbances it is reasonably likely that an outage of the West Andover transformer could occur more than once in ten years. Further, the record demonstrates that an outage of the West

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24/ The Company provided a record of outages for the West Andover substation since the 1984 installation of the 34.5 kV system (Exhs. HO-N-27, NEP-1, p. 4). The Company's record indicates that since 1984, outage of the West Andover transformer caused interruption in customer service on six occasions (Exh. HO-N-27).

25/ The contingency of an outage of the L164 line is not analyzed in regard to the 20 MW criterion because (1) the system design criteria specify that an overhead line can be repaired within 24 hours, and (2) outage records indicate that outages of three hours or more have occurred less frequently than once every three years (Exhs. NEP-2, attachment RHS-9, sec. 2.5.1, HO-N-10). Further, the Company presented no additional evidence supporting the likelihood that the frequency of outages of three hours or more would increase.

26/ Although the Company expects to have a new mobile tranformer within one year, the record indicates that the Company's past reliance on a mobile transformer has not enabled it to fulfill its reliability criteria (Tr. 1, pp. 59-64).

Andover transformer could take longer than 24 hours to repair. Accordingly, based on the Company's 20 MW criterion, the Siting Council finds that supply to the West Andover 34.5 kV load is non-firm in the event of the outage of the West Andover transformer.

d. Conclusions on Reliability of Supply

The Siting Council has found that the Company's future load assumptions are acceptable, the Company's reliability criteria are reasonable and that the Company used reviewable and appropriate methods for assessing system reliability based on load flow analyses.

With respect to the Lawrence Area, the Siting Council has found that the Company has demonstrated that supply will fail to meet reliability criteria at 1992 peak load conditions under the contingency of the outage of one 115/23 kV transformer at the West Methuen substation. Additionally, the Siting Council has found that the Company has demonstrated that supply will fail to meet reliability criteria at 1995 peak load conditions under the contingency of the loss of the 115 kV Y151 transmission line.

With respect to the 34.5 kV load supplied by the West Andover substation, the Siting Council has found that the Company has demonstrated that the supply to the 34.5 kV load currently fails to meet the Company's 20 MW reliability criterion in the event of the loss of the West Andover transformer.

Based on the foregoing, the Siting Council finds that the Company has demonstrated that its existing supply system is inadequate to satisfy expected loads in the Lawrence Area and that its existing distribution system is inadequate to satisfy existing load supplied by the West Andover substation. Accordingly, the Siting Council finds that additional energy resources are needed for reliability purposes in the Lawrence Area.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council to evaluate proposed projects in terms of their consistency with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing or storing, (b) other sources of electrical power or natural gas, and (c) no additional electrical power or natural gas.[27]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. BECo/MWRA, 19 DOMSC at 18-30; 1989 MECo Decision, 18 DOMSC at 20-39; Turners Falls Limited Partnership, 18 DOMSC 141, 166-170 (1988) ("Turners Falls"); 1988 Braintree Decision, 18 DOMSC at 25-27; 1988 CELCo Decision 17 DOMSC at 279-288; 1988 Middleborough Decision, 17 DOMSC at 219-225; 1986 CELCo Decision 15 DOMSC at 212-218; 1985 MECo Decision, 13 DOMSC at 141-183; 1985 BECo Decision, 13 DOMSC at 67-68, 73-74.

In addition, the Siting Council has required a petitioner to consider reliability of supply as part of its showing that its proposed project is superior to alternative project approaches. BECo/MWRA, 19 DOMSC at 25; 1989 MECo Decision, 18 DOMSC at 404-405.

2. Project Approaches

In its initial filing, the Company identified three approaches to meet the identified need: (1) the proposed project, which includes 115 kV transmission facilities and new

27/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the petitioner's proposed site, as well as other site locations, in Section III, below.

transformers at the West Andover and South Broadway substations; (2) an alternative approach, which includes new transformer capability at the West Methuen and West Andover substations and related 23 kV transmission facilities; and (3) the no-build alternative (Exh. NEP-6, p. 2-4).

During the course of the proceeding, additional approaches to meet the identified need were identified and evaluated (Exhs. HO-S-5, HO-RR-12; Tr. 2, pp. 27-44). These approaches are accelerated C&LM and interconnection of potential generation projects with the Company's transmission system (id.).

The Siting Council's analysis of project approaches will include the proposed project, the alternative approach identified by the Company, and the project approaches identified during the course of the proceeding.[28]

3. Ability to Meet the Identified Need

In its analysis of the ability of each of these approaches to meet the identified need, the Siting Council evaluates whether an approach would provide: (1) firm supply to the Lawrence Area with the outage of one West Methuen transformer under 1992 forecasted peak load; (2) firm supply to the Lawrence Area with the outage of the 115 kV Y151 transmission line under 1995 forecasted peak load; and (3) firm supply to the 34.5 kV load currently served by the West Andover substation with the outage of the West Andover transformer.

a. Proposed Project

NEPCo's proposed project includes the new South Broadway line and West Andover tap -- 115 kV transmission lines extending

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28/ Although the Company considered a "no-build alternative" under which no action would be taken to provide additional energy resources, the Siting Council has found that the Company's existing supply system is inadequate to satisfy anticipated loads in the Lawrence Area and that the Company's existing distribution system is inadequate to satisfy the existing load supplied by the West Andover substation (see Section II.A.3.d, above). Therefore, the Siting Council does not consider the no-build alternative in its analysis of project alternatives.

from the existing 115 kV Y151 transmission line in the Town of Tewksbury to the South Broadway and West Andover substations (Exh. NEP-6, p. 2-4). The proposed South Broadway line and West Andover tap would supply a proposed 115/23 kV transformer at the South Broadway substation and a proposed 115/34.5/13.8 kV transformer at the West Andover substation (id.).

With regard to the contingency of the loss of one West Methuen transformer under 1992 peak load conditions, the Company indicated that installation of the proposed South Broadway line and 115/23 kV transformer would reduce the total power flow through the West Methuen substation by six MVA (Exhs. HO-N-29, HO-N-12c; Tr. 2, p. 19). The Company's load flow analysis of this contingency, with the proposed facilities in place, demonstrates that the remaining West Methuen transformer would be loaded at approximately 57.8 MVA, which is within, but relatively close to, its emergency capability of 62 MVA (Exhs. HO-N-12c, HO-N-29, NEP-6, Table 2-1).

In addition to the proposed project, the Company stated that it plans to construct a new substation in Salem, New Hampshire, and a new 115 kV transmission line to supply that substation, in 1993 (Exh. HO-RR-11).[29] With the Salem substation and the proposed project, the loading on the existing West Methuen transformer would be reduced substantially under this contingency (Exh. HO-41b). Thus, the forecasted peak load at the remaining West Methuen transformer would be relatively close to the emergency capability of the transformer only for one year, until the Salem, New Hampshire substation and transmission line are in place in 1993 (id., Exh. HO-RR-11).

With regard to the contingency of the loss of the Y151 line under anticipated 1995 peak load conditions, the Company stated that the installation of the proposed second 115/23 kV South Broadway transformer would allow the substation load to be shared by the two transformers (Tr. 1, p. 132). Accordingly, the

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29/ The Company indicated that in addition to serving load in the Lawrence Area, the the West Methuen substation serves load in Haverhill, Massachusetts and southern New Hampshire (Exh. HO-RR-11, 1990 study, p. 2).

Company stated that the installation of the proposed South Broadway facilities would preclude the overloading of either of the South Broadway transformers under this contingency (Tr. 1, p. 170).

However, the proposed new South Broadway line and transformer would be interconnected with the Y151 line and thus would be out of service when the Y151 line is out of service, as reflected in the Company's load flow analysis of the loss of the Y151 line with the proposed facilities in place (Exh. NEP-2, attachment RHS-11). Therefore, the addition of the proposed South Broadway line and transformer, as initially proposed, could not meet the identified need under this contingency (id.).

In response to the inability of its initial proposal to meet the identified need at the South Broadway substation, the Company asserted that switching adjustments could be installed on the Y151 line in order to maintain power flow to the South Broadway substation in the event of the outage of any portion of the Y151 line (Tr. 2, pp. 5-6). The Company indicated that the installation of automatic switching on the Y151 line, both to the north and south of the tap point for the proposed new South Broadway line, would enable the South Broadway line to remain in service in the event of a short-circuit on any portion of the Y151 line (id., pp. 8-9). Thus, both the existing and proposed South Broadway transformer would remain in service under this contingency.

Finally, the Company asserted that the proposed facilities would provide firm supply for the 34.5 kV load supplied by the West Andover substation (Exh. NEP-6, p. 1-1). The Company indicated that the installation of the proposed West Andover tap line and transformer at the West Andover substation would allow for automatic transfer of the 34.5 kV load in the event of the loss of the existing 115 kV transmission line or the existing 115/34.5/13.8 kV transformer (Brief, p. 7).

Based on the record, the Siting Council finds that the Company has demonstrated that: (1) the proposed project would address the identified need, under the contingency of loss of one

West Methuen transformer, to provide firm supply to the Lawrence Area to meet 1992 peak load; (2) the proposed project, in conjunction with appropriate switching adjustments to the 115 kV system, would address the identified need, under the contingency of loss of the Y151 line, to provide firm supply to the Lawrence Area to meet 1995 peak load;[30] and (3) the proposed project would address the identified need, under the contingency of the loss of the West Andover transformer, to provide firm supply to the 34.5 kV distribution load supplied by the West Andover substation. Accordingly, the Siting Council finds that the proposed project approach, in conjunction with appropriate switching adjustments to the 115 kV system, would meet the identified need.

b. West Methuen Alternative

The Company presented the alternative project approach of expansion of the transformer capacity at the West Methuen substation and construction of related 23 kV transmission facilities ("West Methuen alternative") (Exh. HO-A-1).[31] The West Methuen alternative consists of: (1) interconnecting the two existing 50 MVA 115/23 kV transformers at the West Methuen substation; (2) installing a new 100 MVA 115/23 kV transformer at the West Methuen substation;[32] (3) installing two new 23 kV

30/ The Siting Council considers the switching adjustments on the Y151 line to the north and south of Tewksbury Junction, which would maintain power flow to the South Broadway substation in the event of the outage of any portion of the Y151 line, to be an integral part of the Company's proposed project.

31/ The existing West Methuen substation consists of two 50 MVA 115/23 kV transformers that are supplied by the G133 and Y151 115 kV transmission lines (Exhs. HO-N-12i,j, NEP-2, p. 6, NEP-6, Figure 2-1). Two 23 kV lines originating at the West Methuen substation feed directly into Lawrence (Exh. NEP-2, p. 3). In addition, these 23 kV lines tie east to Ward Hill and furnish supply to Salem, New Hampshire (id.).

32/ The Company noted that physical constraints at the West Methuen substation might require replacing both of the existing 50 MVA transformers with 100 MVA transformers, rather than installing one new transformer (Exh. HO-N-45).

transmission lines from the new transformer at the West Methuen substation, one extending to the South Broadway substation and the other to the West Andover substation; (4) installing a new 23/34.5 kV transformer at the West Andover substation; and (5) installing a new 23 kV circuit breaker in the existing bus at the South Broadway substation (Exh. HO-A-2).[33]

The Company asserted that the West Methuen alternative would accomplish the same system reinforcements as the proposed project (Exh. HO-A-5). The Company stated that the West Methuen alternative would address the identified need, under the contingency of loss of one West Methuen transformer, to provide firm supply to the Lawrence Area for 1992 peak load by providing back-up capability to the West Methuen substation via the 23 kV line to South Broadway (Tr. 2, pp. 51-63). The Company further stated that the West Methuen alternative would address the identified need, under the contingency of loss of the Y151 line, to provide firm supply to the Lawrence Area for 1995 peak load by providing 50 MVA of additional capacity at the South Broadway substation (id.). Finally, the Company stated that the West Methuen alternative would address the identified need, under the contingency of the loss of the West Andover transformer, to provide firm supply to the 34.5 kV distribution load served by the West Andover substation by providing 50 MVA of additional capacity at the West Andover substation (id.). The Company stated that the alternative facilities therefore would provide firm supply to the loads supplied by the West Andover and South Broadway substations as well as provide additional back-up to the West Methuen substation in the event of the loss of one of the two existing West Methuen transformers (id., p. 52,

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33/ The Company noted that the West Methuen alternative does not include a 23 kV interconnection between the existing 50 MVA transformers and the new 100 MVA transformer (Tr. 2, p. 57).

pp. 57-58).[34]

Based on the record in this proceeding, the Siting Council finds that the West Methuen alternative would meet the identified need.

c. C&LM Alternative

In response to a request of the Siting Council, the Company addressed acceleration of conservation and load management programs as a project approach to meet the identified need (Tr. 2, pp. 27-32). The Company analyzed the reduction in load growth in the Lawrence Area that could be achieved under this project alternative such that additional facilities would not be necessary to ensure firm supply through the forecast period (id.).

The Company indicated that its peak load forecast for 1989 through 1992 for the Lawrence Area includes the effects of diverse C&LM programs that either are implemented or planned to be implemented by 1992 (Exh. HO-N-5). The Company estimated that its system-wide peak load forecast was reduced by 148.9 MW (3.6 percent) in 1989 due to the implementation of C&LM programs (Exhs. HO-N-21, HO-RR-12). The Company further indicated that, based on its 1991 system update, system-wide peak load will be reduced by 369.1 MW (8 percent) in 1992 due to C&LM (Exh. HO-N-38).

The Company stated that the majority of its C&LM programs are directed toward commercial and industrial customers (Tr. 1, p. 21). The Company further stated that, due to the highly

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34/ The Company also provided an analysis of a different version of the West Methuen alternative wherein the 23 kV bus for the third West Methuen transformer is interconnected with the 23 kV bus for the existing transformers (Exh. HO-N-45). This version of the West Methuen alternative does not include the new 23 kV line between the West Methuen substation and the South Broadway substation (id.). However, the Company indicated that loadings on the existing 23 kV lines would be noticeably higher under this version than under the original West Methuen alternative, requiring costly reinforcements to segments of these lines and equipment in the West Methuen substation (id.).

commercial and industrial nature of the Lawrence Area, the benefits of the C&LM programs likely would be greater in the Lawrence Area than in the system in general (id.). The Company estimated that the benefits of the C&LM programs to the Lawrence Area might be as much as 20 percent greater than the benefits to its overall system (id.). The Company asserted that its most recent forecast of Lawrence Area load, based on its 1991 system update, included the effect of increased C&LM benefits to the Lawrence Area (Exh. HO-N-39).

The Company indicated that, by increasing personnel and effort, certain C&LM programs likely could be accelerated and implemented before 1992, thereby increasing the peak load megawatt savings provided by these programs by approximately 10 percent by 1992 (Tr. 2, pp. 27-28, 30). Thus, the Company estimated that the the potential 1992 system-wide peak load megawatt savings due to acceleration of C&LM programs would be 14 MW, or a peak load reduction of 0.3 percent.

The Siting Council notes that, in allocating system-wide peak load megawatt savings to the Lawrence Area, the system-wide savings should be increased by 20 percent due to the likelihood that the C&LM benefits to Lawrence would be greater than the system-wide benefits. Thus, the acceleration of C&LM programs would lead to a reduction in 1992 Lawrence Area peak load of 0.36 percent, or 1.1 MW, thereby reducing the 1992 peak load forecast from 308.2 MW to 307.1 MW. As noted in Section II.A.3.c.i, above, the Company has demonstrated that additional energy resources will be required in the Lawrence Area in 1992 when the area peak load will exceed 300 MW.

In addition, the Siting Council notes that megawatt savings of C&LM programs have not been allocated to the supply substation level within the Lawrence Area. However, even if the entire 1.1 MW reduction attributed to accelerated C&LM programs were applied to the 34.5 kV load supplied by the West Andover substation, the 34.5 kV load, which peaked at 21.5 MW in 1989, would remain above the Company's 20 MW threshold for firm supply within a contiguous area.

Based on the foregoing, the Siting Council finds that acceleration of C&LM programs fails to address the identified need.

d. Generation Alternative

In response to a request of the Siting Council, the Company addressed the introduction of additional capacity to the Lawrence Area 23 kV subtransmission system through the interconnection of potential new generation facilities as a project approach to meet the identified need (Tr. 2, pp. 34-41, 44-50).

The Company stated that relatively small generation facilities that were dispersed geographically over the Lawrence Area would likely provide benefit to the Lawrence Area supply system (Tr. 2, p. 36). The Company further stated that in order for a generating facility to have a beneficial effect on the loading on the West Methuen and South Broadway transformers, interconnection with the 23 kV system would be required (Tr. 2, p. 38). The Company estimated that a maximum load of 40 MW from an individual project could be directly connected to the 23 kV system (id.).

The Company identified two potential cogeneration projects within the Lawrence Area that possibly could affect the loading on the West Methuen and South Broadway transformers: (1) the 100 MW Malden Mills Project, which was initially proposed as a 32 MW project; and (2) the 24 MW CPC Project (Exh. HO-S-5).[35] The Company stated that the developers of these projects have not requested interconnection studies to identify how these proposed cogeneration projects, as currently proposed, would be connected to the Company's transmission

35/ The Company originally identified two additional facilities, the Canal Cogeneration Project and the Bonneville Pacific at Emerson College (Exh. HO-S-5). The Company indicated that the size of the Canal Cogeneration Project (55 MW) would prohibit its interconnection with the 23 kV system (Tr. 2, pp. 37-38). The Company added that the Bonneville Pacific project has been cancelled (Tr. 2, p. 40).

system (id.; Tr. 2, p. 35). The Company further stated that it does not consider any of these projects to be active at the current time (id.).

In discussing generation as an alternative to construction of the proposed facilities, the Company stated that its planning process does not include incentives to foster implementation of potential cogeneration/independent power production projects that could delay the need for transmission or distribution system improvements by the Company (HO-N-35). The Company further stated that, in general, it would not include a generation facility in its planning process until it was visibly under construction (id.). Finally, the Company explained that it considers generation, in general, to be the most costly way of solving an area supply problem (id.).

The record indicates that none of the generating facilities proposed for the Lawrence Area has progressed in its development to a point where it is reasonable that the Company should include it in its system planning. Based on the foregoing, the Siting Council finds that additional generation in the Lawrence Area would not meet the identified need.

While the Siting Council has found that the specific cogeneration projects in the Lawrence area have not progressed to a point where it would have been reasonable for the Company to have considered these projects in its system planning, we have some serious concerns regarding the Company's general policies relative to the integration of non-utility generation projects in its transmission planning. In particular, the Siting Council notes that the Company's general policy of excluding a cogeneration project from its planning process until such project is "visibly under construction" is a policy which may operate at direct odds with the best interests of the Company's customers and the Commonwealth's stated goal of encouraging least-cost cogeneration projects which minimize environmental impact.

In a recent case, the Siting Council emphasized the benefits which can flow to a company's customers and the region when an electric company employs a comprehensive transmission planning policy which incorporates consideration of both system needs and the interconnection of non-utility generation facilities. In its 1989 MECo Decision, the Siting Council rejected the Company's proposal to build a new transmission line in favor of reconductoring an existing line. However, in rejecting the Company's proposed transmission line approach, the Siting Council noted that the Company's proposed approach might have been warranted if the Company had appropriately considered the potential cost and reliability benefits that the alternate approaches could have provided to its ratepayers (1989 MECo Decision, 18 DOMSC at 424).

The factual situation in the 1989 MECo decision differs from the circumstances in this proceeding. However, the principle that companies should fully consider potential non-utility generating projects in system planning applies equally in both cases. Active consideration of interconnection of potential generating facilities as an alternative or a complement to transmission facility upgrades is not only appropriate, but necessary to a comprehensive analysis of alternative project approaches. The Siting Council expects utilities to include potential interconnection of non-utility generation facilities as an integral part of all future analyses of transmission upgrades.

In setting out this expectation, the Siting Council is not requiring Companies to plan transmission projects based on non-utility generating projects which have not progressed in the planning process in order to provide some degree of certainty regarding their potential impact on the transmission system. Rather, we are stating that a system planning process which proceeds completely independently from an interconnection planning process is not consistent with least-cost planning principles.

e. Conclusions on Ability to Meet the Identified Need

The Siting Council has found that the Company has demonstrated that both the proposed project, in conjunction with appropriate switching adjustments to the 115 kV system, and the West Methuen alternative would address the identified need. The Siting Council also has found that the Company has demonstrated that the C&LM alternative and the generation alternative fail to address the identified need.

Accordingly, the Siting Council evaluates the cost, environmental impacts and reliability of the proposed project in conjunction with appropriate switching adjustments to the 115 kV system and the West Methuen alternative.

4. Cost

The Company asserted that the proposed project would be the least cost alternative to meet the identified need (Exh. HO-A-2). In support of its assertion, the Company provided cost estimates for both the proposed project and the West Methuen alternative (Exhs. HO-C-5, HO-A-2, HO-N-44). The Company explained that the cost estimates provided during the proceeding are "study grade" costs, with an accuracy of plus or minus 25 percent (Exhs. HO-C-5, HO-A-2).

The Company estimated that the cost of the transmission lines associated with the proposed project would range from $1,588,900 for the primary route to $2,618,000 for the alternative route (Exh. HO-C-5). The Company stated that it already has purchased a transformer for the West Andover substation, and that the cost of the transformer was $460,000 (Exhs. Exh. HO-N-44, Tr. 3, p. 70). The Company did not provide cost estimates for the proposed transformer at the South Broadway substation, nor for the switching equipment on the Y151 transmission line.

The Company estimated that the costs associated with the West Methuen alternative would total $11,430,000 (which includes $9,600,000 for transmission lines and $1,830,000 for substation modifications) (Exh. HO-A-2). In addition, the Company asserted that the West Methuen alternative would result in greater line losses than the proposed project, such that the proposed project, relative to the West Methuen alternative, would produce savings which increase from $397,000 in 1992 to $936,000 in 1999 (Exh. HO-N-46).

Thus, the record demonstrates that, even if the cost of the proposed project is 25 percent higher than the $2,618,000 estimate for the alternative route, and the cost of the West Methuen alternative is 25 percent lower than the $11,430,000 currently estimated, the proposed project would cost $4,840,000 less than the West Methuen alternative.[36] Additionally, the line loss savings associated with the proposed project indicate that the operational costs of the proposed project are considerably lower than the operational costs associated with the West Methuen alternative.

Accordingly, the Siting Council finds that the proposed project in conjunction with appropriate switching adjustments to the 115 kV system is superior to the West Methuen alternative with regard to cost.

5. Environmental Impacts

The Company stated that the environmental impacts of the West Methuen alternative would be greater than the environmental impacts of installation of its proposed project (Exh. HO-A-4).

The Company indicated that the proposed project would include one overhead 115 kV transmission line, ranging in length from 5.5 to 5.7 miles along existing ROWs, and one new

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36/ Although the cost estimate for the proposed project does not include the new South Broadway transformer and Y151 switching adjustment, the cost of the West Andover transformer, as well as the cost of switching adjustments that will be installed in conjunction with the Salem, New Hampshire substation, indicate that the new transformer and switching would cost far less than $4,840,000 (Exhs. HO-N-44, HO-RR-11, 1990 study).

transformer at each of two existing substations (Exh. NEP-6, p. 2-4).[37] In addition, the Company stated that existing double circuit poles would be utilized for one portion of the new transmission line (id., p. 2-5). Finally, the Company stated that additional space would not be required to accommodate the new transformers at either substation (Exh. HO-22).

With regard to the West Methuen alternative, the Company indicated that construction would include overhead and underground construction of two 23 kV transmission lines along a 5.7 mile route,[38] installation of one new transformer at each of two existing substations, and 23 kV bus modifications at a third existing substation (Exh. HO-A-2). The Company stated that for the majority of the overhead portion of the transmission lines, each line would be constructed on a separate single circuit steel pole (id.).

The Company further stated that one of the 23 kV lines under the West Methuen alternative would be constructed along the segment of the proposed project's 115 kV line route where

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37/ The Company stated that underground construction at one road crossing in downtown Lawrence likely would be required in order to construct the Company's proposed project along the alternative route (Exh. HO-A-5).

38/ The Company indicated that the two 23 kV lines would extend from the West Methuen substation to the South Broadway substation (Exh. HO-A-2). The Company stated that one line would terminate at the South Broadway bus and the second line would continue past the South Broadway substation to the West Andover substation (id.). Additionally, the Company stated that, with the exception of the first 4,000 feet from the West Methuen substation, the 23 kV lines would be constructed along the Company's alternative route for the proposed project (id.). Thus, two lines would be constructed for approximately 3.3 miles and one line would be constructed for an additional 2.2 miles (id., NEP-6, p. 2-5).

the 115 kV line would be constructed on existing double circuit poles (id.). The Company stated that, although only one 23 kV line would be required along this portion of the route, the increased weight of the 23 kV line in relation to the existing 115 kV line would require the existing poles to be removed and replaced with larger poles (id.). In addition, the Company stated that due to ROW constraints, underground construction of both 23 kV lines likely would be required for the first 4,000 feet of the route extending across wetlands that border a wildlife area in Methuen (id., Exhs. HO-A-5, HO-RR-19, Attachment T-33174). Furthermore, the Company stated that underground construction of both 23 kV lines likely would be required for one street crossing in downtown Lawrence (Exhs. HO-A-2, HO-A-5).[39] Finally, the Company stated that an expanded substation area would likely be required at one substation (Exh. HO-A-2).

The record indicates that the Company's proposal would require construction of one transmission line, utilize existing double circuit poles along a portion of the route and would not require any expansion of substation areas. The record further indicates that the West Methuen alternative would require: (1) construction of two transmission lines; (2) removal and replacement of existing double circuit poles; (3) expansion of substation areas; and (4) underground construction within a sensitive area. Finally, the record indicates that the transmission lines that would be constructed under the Company's proposal and the West Methuen alternative would be of comparable length.

In comparing the environmental impacts of the Company's proposal with the environmental impacts of the West Methuen alternative, the Siting Council notes that, in general, the

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39/ The Company indicated that this is the same location where underground construction likely would be required for construction of the Company's proposed project along the alternative route (Exh. HO-A-5).

construction of two transmission lines under the West Metheun alternative would have greater siting impacts on natural resources and visual impacts than construction of one transmission line under the Company's proposal. Further, installation of low voltage lines under the West Methuen alternative would result in generally higher magnetic field levels than installation of a high voltage line carrying a comparable amount of power.

In addition, the Siting Council notes that, in general, the expansion of an existing substation under the West Methuen alternative would have greater land use and natural resources impacts than installation of facilities within an existing substation area. The Siting Council further notes that removal and replacement of existing poles with larger poles under the West Metheun alternative would have greater visual and construction impacts than utilization of existing poles under the Company's proposal. Finally, the Siting Council notes that underground construction required under the West Methuen alternative could have a significant impact on an environmentally sensitive area.

Based on the foregoing, the Siting Council finds that the Company's proposed project in conjuction with appropriate switching adjustments to the 115 kV system is superior to the West Methuen Alternative with regard to environmental impacts.

6. Reliability

The Company stated that the West Methuen alternative is designed to accomplish the same degree of system improvements as the proposed project (Exh. HO-A-5). The Company indicated that, like the proposal, the West Methuen alternative would provide 50 MVA of additional nominal capability at both the South Broadway substation 23 kV bus and at the West Andover substation 34.5 kV bus (id.).

Based on the foregoing, the Siting Council finds that the proposed project and the West Methuen alternative are comparable with respect to reliability.

7. Conclusions: Weighing Need, Cost, Environmental Impacts and Reliability

The Siting Council has found that: (1) the proposed project in conjuction with appropriate switching adjustments to the 115 kV system and the West Methuen alternative would meet the identified need; (2) that the proposed project in conjuction with appropriate switching adjustments to the 115 kV system is superior to the West Methuen alternative with regard to cost; (3) that the proposed project in conjuction with appropriate switching adjustments to the 115 kV system is superior to the West Methuen alternative with regard to environmental impacts; and (4) that the proposed project in conjuction with appropriate switching adjustments to the 115 kV system is comparable to the West Methuen alternative with regard to reliability.

Accordingly, the Siting Council finds that the Company has demonstrated that its proposed project in conjunction with appropriate switching adjustments on the 115 kV system is consistent with ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

III. Analysis of the Proposed and Alternative Facilities

A. Standard of Review

G.L. c. 164, sec. 69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facility siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined that (a) new energy resources are needed, and (b) the applicant has proposed a project that is, on balance, superior to other broad approaches (which we have termed "project approaches") in terms of cost, environmental impacts, reliability and meeting identified need, the Siting Council has then required the petitioner to show that it has examined a reasonable range of practical siting alternatives. 1990 Bay State Decision, EFSC 89-13, p. 40; MASSPOWER, 20 DOMSC 301, 371; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148; BECo/MWRA, 19 DOMSC at 31; Turners Falls, 18 DOMSC at 171; 1988 Braintree Decision, 18 DOMSC at 31; Altresco-Pittsfield, 17 DOMSC at 387; 1988 ComElectric Decision, 17 DOMSC at 289; 1988 Middleborough Decision, 17 DOMSC at 225; 1988 Boston Gas Decision, 17 DOMSC at 172; NEA, 16 DOMSC at 381. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Council typically has required the proponent to meet a two-prong test: the proponent must establish that (1) it has developed and applied a reasonable set of criteria for identifying and evaluating alternatives, and (2) it has identified at least two routes or sites with some measure of geographic diversity.[40] 1990 Bay State Decision, EFSC 89-13, pp. 40-41; MASSPOWER, 20 DOMSC at 371-372; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148-149; BECo/MWRA, 19 DOMSC at 31-32; Turners Falls, 18 DOMSC at 171-172; 1988 Braintree Decision, 18 DOMSC at 31. Finally, the proponent must demonstrate that the proposed site/route for the facility is superior to the noticed alternative(s) on the basis of balancing cost, environmental impact, and reliability of supply. 1990 Bay State Decision, EFSC 89-13, p. 41; MASSPOWER, 20 DOMSC at 372; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148; BECo/MWRA, 19 DOMSC at 31; Turners Falls, 18 DOMSC at 171; 1988 Braintree Decision, 18 DOMSC at 31; Altresco-Pittsfield, 17 DOMSC at 387; 1988 ComElectric Decision, 17 DOMSC at 289; 1988 Middleborough Decision, 17 DOMSC at 225; 1988 Boston Gas Decision, 17 DOMSC at 172; NEA, 16 DOMSC at 381.

The requirement that a proponent has considered a reasonable range of practical facility alternatives has been extensively discussed in two recent cases, Altresco-Pittsfield and the 1990 Berkshire Decision (Phase II). In Altresco-Pittsfield, the Siting Council focused on the applicability of the second prong of the practicality test -- the requirement that an applicant identify at least two sites or routes with some measure of geographic diversity. In that case, the Siting Council found that an applicant proposing to construct a cogeneration facility could establish, in certain circumstances, that a second practical facility site does not

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40/ When a facility proposal is submitted to the Siting Council, the petitioner is required to present: (1) its preferred facility route or site; and (2) at least one alternative facility route or site. These routes and sites often are described as the "noticed" alternatives because these are the only routes and sites described in the notice of adjudication published at the commencement of the Siting Council's review. In reaching a decision in a facility case, the Siting Council can approve a petitioner's preferred route or site, approve an alternative route or site, or reject all routes and sites. The Siting Council, however, may not approve any site, route, or portion of a route which was not included in a notice of adjudication published in the proceeding.

exist, and, thus, need not provide a "noticed" alternative site (17 DOMSC at 394). However, Altresco-Pittsfield did not change the requirement that an applicant comply with the first prong of the practicality standard -- that an applicant develop and apply a reasonable set of criteria for identifying and evaluating alternatives. Nor did Altresco-Pittsfield alter the requirement that in cases where a noticed alternative is required, the noticed alternative must be geographically distinct from the primary site/route.

In the 1990 Berkshire Decision (Phase II), the Siting Council focused on the first prong of the practicality standard, commonly referred to as the site selection process. In that case, the Siting Council fully examined the purpose and intent of its review of the siting alternatives, emphasizing the importance of developing and applying a reasonable set of criteria for identifying and evaluating alternatives through the site selection process (20 DOMSC at 41). In that same case, the Siting Council stated that a facility proponent is required to present to the Siting Council a description of its site selection process, including a full explanation of the criteria developed and applied in making siting decisions. Id. The 1990 Berkshire Decision further stated that a review of a comprehensive site selection process, as opposed to a review of the "practicality" of a noticed alternative, is the best way to ensure a reasonable range of practical siting alternatives has been considered. A comprehensive site selection process will ensure that the petitioner has not overlooked or eliminated any alternative route or site -- irrespective of whether it has been included in a published legal notice -- which clearly is superior to the petitioner's preferred route or site.[41]

In order to determine whether the Company has considered a reasonable range of practical alternatives, the Siting Council first reviews the Company's site selection process to evaluate whether the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives which ensures that the Company has not overlooked or eliminated any route or site which is clearly superior to its preferred route or site (see Section III.C.2, below). Next, we consider whether that process included consideration of route alternatives with some measure of geographic diversity (see Section III.C.3, below).

Finally, if a petitioner can establish that it has considered a reasonable range of practical siting alternatives, the Siting Council still must review whether the preferred route or site is superior to noticed alternative routes and sites (see Sections III.D, III.E, and III.F, below). This finding is essential because it is at this stage that the Siting Council determines whether routes or sites are acceptable, i.e., whether they achieve the appropriate balance between cost, environmental impact and reliability. Further, because we expect petitioners to present in their filing alternatives that are, in fact, responsible and reasonable, this more detailed analysis of the noticed alternatives enables the Siting Council to determine which route or site is superior in terms of achieving the appropriate balance between cost, environmental impact and reliability.

41/ In making this distinction, the Siting Council does not mean to invite parties to present an exhaustive list of possible alternative routes and sites which must then be evaluated in our proceeding relative to the preferred route or site. Instead, through a comprehensive review of the petitioner's site selection process, i.e., a consideration of how specific criteria were developed and applied, the Siting Council can determine whether clearly superior routes or sites have been overlooked or eliminated.

B. Description of the Proposed and Alternative Facilities

1. Proposed Facilities

The Company's proposal consists of construction of a new 5.7-mile 115 kV transmission line that would extend from Tewksbury Junction, a tap on the existing Y151 115 kV transmission line,[42] to the West Andover and South Broadway substations (Exh. NEP-6, p. 3-1). The proposed transmission line along the primary route consists of (1) a 5.2-mile 115 kV transmission line extending from Tewksbury Junction to the South Broadway substation ("South Broadway line"), and (2) a 0.5-mile 115 kV tap line extending from the West Andover tap on the South Broadway line to the West Andover substation ("West Andover tap line") (Exh. NEP-6, p. 2-5). The proposed transmission line along the primary route would be located in the Towns of Tewksbury and Andover and the City of Lawrence, and would be placed within existing electric utility ROWs for its entire length (id., p. 3-1). Figure 2 is a map of the primary route.

The primary route for the South Broadway line begins at Tewksbury Junction and travels in a northeasterly direction in the Towns of Tewksbury and Andover and the City of Lawrence to the South Broadway substation (Exh. HO-E-16). The primary route crosses three waterways: Fish Brook in the Town of Andover; a tributary to Haggetts Pond in the Town of Andover; and a small tributary to the Merrimack River in the City of Lawrence (Exh. NEP-6, p. 3-3). It also crosses Interstate Route 93 in Andover and a number of local roads in both Andover and Lawrence (Exh. HO-E-16).

The primary route for the West Andover tap line begins at the West Andover Tap, which is located on the South Broadway line, to the west of North Street, and continues in a northerly direction for 0.5 miles to the West Andover substation (Exh. NEP-6, Figure 3-6). It crosses a number of local streets in Andover (id.).

Configuration of proposed facilities along the primary

42/ This section of the Y151 transmission line extends from Tewksbury to West Methuen (Exh. NEP-6, Table 2-2).

route would vary according to the width of the ROW and location of existing structures within the ROW (Exh. NEP-6, Figures 3-2, 3-3, 3-4 and 3-5).

The portions of the route from Tewksbury Junction to the West Andover tap (Figure 2, Segment AB) and from the West Andover tap to the West Andover substation (Figure 2, Segment BC) are presently occupied by (1) an existing 115 kV transmission line (the L-164 line),[43] and (2) an existing 13.2 kV distribution line (id., p. 3-1). Within these segments, the ROW is approximately 150 feet wide (id., Figures 3-2, 3-5). The proposed transmission line would be constructed primarily on new single circuit wood pole structures utilizing three steel davit arms (Exh. NEP-5, p. 4). The wood poles would be approximately the same height (65 feet on average) as the wood poles supporting the existing 115 kV transmission line (id., p. 5). The proposed line would be placed approximately 30 to 33 feet to the south of the existing 115 kV line (id., Exh. NEP-6, Figures 3-2, 3-3, 3-4 and 3-5).

The Company identified two areas in Andover within this portion of the primary route which reflect design changes made to accommodate concerns of abutters (Exh. HO-S-4). At the North Street intersection (Figure 2, Segment AB), the Company has agreed to narrow the cleared ROW by rebuilding and relocating existing structures in order to increase the distance between residences located in close proximity to the ROW and the new transmission line in order to avoid clearing 17 feet of vegetation (id., Exhs. HO-S-6, HO-E-36).[44] Likewise, at the

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43/ The L-164 transmission line supplies the existing transformers at the West Andover and South Broadway substations (Exh. NEP-6, p. 2-5).

44/ With regard to the North Street area, the Company indicated that the H-frame structures supporting the existing 13.2 kV and 115 kV lines would be removed and replaced by single pole structures which would be relocated toward the northwest side of the ROW (Exhs. NEP-5, p. 11, HO-S-6, HO-E-36). The Company stated that with this relocation, the new line also would be located toward the northwest side of the ROW, resulting in a narrowed cleared ROW and an increase in the distance between residences and the new line (id.).

intersection of the West Andover tap line and Webster Street (Figure 2, Segment BC), the Company has agreed to rebuild and relocate the existing 115 kV line in order to increase the distance between the proposed transmission line and a residence located within the ROW (Exhs. HO-S-4, HO-S-6).[45]

The portion of the route from the West Andover tap to the South Broadway substation also is occupied by the existing 115 kV transmission line (id., pp. 3-1, 3-2). For the first 0.2 miles of this segment (Figure 2, Segment BD), the existing ROW is 150 feet wide, and the proposed construction would be comparable to construction along the Tewksbury Junction to West Andover substation segment described above (id., Figure 3-3). For the remaining 1.5 miles of the primary route (Figure 2, Segment DE), the ROW width varies from 50 to 82.5 feet (id., Figure 3-4). In this segment, the existing 115 kV transmission line is located on 90-foot, steel pole structures with a double set of davit arms (Exh. NEP-6, Figure 3-4).[46] The proposed transmission line would be installed on the unoccupied side of the existing poles along this segment of the route (id., p. 3-2).

In addition, the Company's proposal includes the installation of new transformers at the South Broadway and West Andover substations (Exh. NEP-6, p. 1-1). The Company indicated that the installation of the transformers would not require an increase in the area of either substation (Exh. HO-E-22).

45/ With respect to Webster Street, the Company indicated that the existing 115 kV line would be transferred to a new structure, which would be located to the west of the existing structure (Exh. HO-S-6). The Company stated that the new line would then be installed on the existing structure, thereby increasing the distance of both lines from the residence, relative to the rest of the segment (id.).

46/ The Company indicated that the pole structures along this segment of the ROW were installed in 1964 and were designed to accommodate a second circuit that the Company determined eventually would be needed in the South Broadway/West Andover area (Exh. HO-E-23). The Company stated that it selected steel poles to support both circuits due to ROW limitations (id.).

2. Alternative Facilities

The Company's alternative route extends from Methuen Junction, a tap on the West Methuen to Ward Hill G-133 115 kV transmission line in the Town of Methuen, to the South Broadway and West Andover substations (id., pp. 3-6 to 3-7). The alternative route is located within existing transmission line ROWs and within the Boston and Maine ("B&M") railroad corridor in the Towns of Methuen and Andover and the City of Lawrence (id.). Figure 3 is a map of the alternative route.

The segment of the alternative route from Methuen Junction to the South Broadway substation (3.3 miles) is unique to the alternative route, while the segment of the alternative route from the South Broadway substation to the West Andover substation (2.2 miles) is common to both the primary and alternative routes (id.).

The alternative route begins at Methuen Junction and proceeds in an easterly direction for 0.2 miles, across the Nevins Wildlife Refuge to the B&M ROW (Exh. NEP-5, p. 13). The alternative route then proceeds in a southerly direction along the B&M corridor through downtown Lawrence to the South Broadway substation (Exh. NEP-6, Figure 3-12). The alternative route then turns to the west and continues along the primary route to the West Andover substation (id.). In Methuen, the alternative route crosses the Spickett River and a pond associated with the Spickett River which is located within the Nevins Wildlife Refuge (Exhs. NEP-6, Figure 3-12, p. 3-9, HO-E-16). In Lawrence, the alternative route crosses State Roads 113, 110 and 28, a number of smaller roads, the Merrimack River and associated canals, and a tributary to the Merrimack River (id.).

The configuration of the proposed facilities along the alternative route, like the primary route, would vary according to the width of the existing ROWs and location of railroad tracks and existing structures within the ROWs (Exh. NEP-6, Figures 3-8, 3-9, 3-10 and 3-11). For the first 0.2 miles of the alternative route, from Methuen Junction to the B&M railroad tracks, the existing electric transmission line ROW is occupied by two 23 kV subtransmission lines (Figure 3, Segment FG) (Exh. NEP-6, p. 3-7, Figure 3-8). This existing electric transmission line ROW ranges from 100 to 200 feet in width and the proposed 115 kV transmission line would be constructed on wooden H-frame structures, averaging 48 feet in height, approximately 36 feet to the east of the existing lines (id.).

For the remaining 3.1-mile distance to the South Broadway substation, the alternative route would be built on steel-pole structures, adjacent to the B&M railroad tracks, on B&M property (Figure 3, Segment EF) (id., p. 3-7). This portion of the route is occupied by underground and overhead portions of a third 23 kV subtransmission line (the 2355 line) (id.). The width of the B&M ROW varies from 62 to 162.5 feet (Exh. NEP-6, Figures 3-9, 3-10, 3-11). Construction along this portion of the alternative route would vary according to the width of the ROW and the location of the existing 23 kV line (id.). Where the existing 23 kV line is underground, the proposed transmission line would be constructed on single circuit steel poles averaging 80 feet in height (id., Figure 3-9). Where the existing 23 kV line is overhead (a distance of approximately two miles), the proposed 115 kV transmission line would be built on steel structures averaging 80 feet in height, and the existing 23 kV line would be underbuilt on these same structures (id., p. 3-7, Figure 3-10).[47] In order to cross the Merrimack River, both the proposed 115 kV transmission line and the existing 2355 line would be built on steel H-frame structures approximately 100 feet in height (id., Figure 3-11).

The remaining portion of the alternative route, extending from the South Broadway substation to the West Andover substation, is identical to the corresponding section of the

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47/ The Company indicated that the 2355 line could not be taken out of service during construction (Exh. NEP-3, p. 14). Therefore, the Company asserted that specialized construction techniques would be required to permit work to be performed on the energized line (id., p. 15).

primary route (See Figure 3, Segments BD, DE, and CD) (id., p. 3-7).

In addition, two new transformers would be installed, identical to those that would be installed in conjuction with construction of the proposed facilities along the primary route (Exh. NEP-6, p. 1-1).

C. Site Selection Process

As stated in Section III.A, above, the Siting Council examines whether an applicant has developed a reasonable set of criteria for identification and evaluation of possible sites, as well as whether those criteria were applied consistently and appropriately, in such a manner as to ensure that no clearly superior alternatives have been overlooked or eliminated.

1. Development of Siting Criteria

a. Description

The Company indicated that its first siting consideration is identification of any potential transmission line routes within rural corridors (Exh. HO-S-1). The Company further stated that, assuming a rural corridor can be identified, it then considers the following criteria: (1) land use compatibility (highways, railroads, airports, military sites, and existing utility and transportation corridors); (2) physical and topographical constraints (waterways, state parks and forests, reservoirs and flood control projects, major ridge lines, and flood plains); (3) environmentally sensitive areas (wetlands, wildlife refuge areas, prime timbered areas, and historic and archaeological sites); and (4) design, construction and cost features of the route (alignment of the transmission line, width of the ROW, economy of design, property rights, permits, difficulty of construction, construction costs, and ease of maintenance) (id., Exh. HO-S-3).

The Company stated that if no rural corridors exist, urban corridors are identified and evaluated based on: (1) land use along the route, including location of residential clusters, schools and cemeteries; (2) environmental features identical to those for rural routes; and (3) design, construction and cost features identical to those for rural routes (id.).

The Company indicated that it does not consider the location of planned or proposed generating facilities which do not have firm interconnection commitments in its process for the siting of transmission lines (Tr. 3, pp. 71-73). However, the Company stated that it would consider new generating facilities with firm interconnection commitments in the siting of a new transmission line (id.).

The Company stated that it does not assign weights to its criteria for identification and evaluation of potential transmission line routes (Exh. HO-S-1). Instead, the Company explained that it must balance the entire scope of considerations against its primary goal, which is to furnish economical, reliable electricity while protecting the environment (id.).

The Company noted that once corridors are identified, the Company meets with abutters to identify potential concerns (Exh. HO-S-4). The Company added that in determining whether to incorporate measures to address abutter concerns, it considers the extent of the economic impact of such measures on the project (id.).

b. Analysis

The Company has developed a reasonable set of detailed site selection criteria that include consideration of land use compatibility, physical and topographical constraints, environmentally sensitive areas, and design, construction and cost constraints. Additionally, the Company indicated that it includes location of proposed generating facilities when those facilities have firm interconnection commitments.

However, the Company acknowledged that it does not assign weights to its site selection criteria. The Company instead stated that it balances all siting considerations against its primary goal of providing economical, reliable electricity while protecting the environment. The Company's approach raises concerns in that it does not clearly state how the potentially competing criteria of cost, environmental impact and reliability are balanced against one another, or how potentially competing components of these criteria are balanced. For instance, within environmental impacts, the Company gives no indication of how it would balance wetlands impacts versus construction in an historically or archaeologically significant area.

In the BECo/MWRA decision, the Siting Council stated that a petitioner's weighting of its chosen screening criteria clearly has a direct and significant impact on the final site selection (19 DOMSC at 42). Further, in that decision, the Siting Council stated that without a showing of how the weights were assigned, the Siting Council could not conclude that the site selection process was unbiased and consistent with achieving a balance between necessary energy supplies, cost, and environmental impacts (id.). The BECo/MWRA decision was issued after NEPCo submitted its filing in this proceeding and we have not required NEPCo to submit weights for screening criteria. However, the instant proceeding is the last facility petition to be decided which was filed with the Siting Council before the BECo/MWRA decision was issued. Future facility petitions must include weighting for screening criteria. Accordingly, the Siting Council reiterates that all petitioners are put on notice that they must demonstrate in their filing how weights are applied to their siting criteria.

Based on the foregoing, the Siting Council finds that the Company developed a reasonable set of criteria for siting the proposed transmission line.

2. Application of Siting Criteria

a. Description

The Company identified only two routes for the proposed

115 kV transmission line: the primary route, which is described in Section III.B.1, above, and the alternative route, which is described in Section III.B.2, above (Exh. HO-S-2). The Company indicated that it could not identify any other feasible routes due to the densely populated area the transmission line must traverse (id.). Additionally, the Company presented a United States Geological Survey map of the Lawrence Quadrangle, with utility and rail rights-of-way highlighted, which indicates that these are the only two existing utility corridors in the area (Exh. HO-E-16). The Company applied its siting criteria to both the primary and alternative routes to determine which route would be the preferred choice (Exh. HO-S-3).

i. Primary Route

The Company asserted that its main consideration in selection of the primary route was its location on an existing electric transmission line ROW (id.). The Company indicated that design and construction of the transmission line along the primary route would be less difficult than design and construction along the alternative route primarily due to its location within an existing ROW of sufficient width, which is occupied only by electric transmission lines (id.). The Company noted that the estimated cost of construction along the primary route would be significantly less (approximately $1,000,000 less) than construction along the alternative route (id.).

The Company analyzed the environmental and visual impacts of the primary route and determined that construction of the proposed facilities along this route would have minimal long-term and short-term environmental impacts and visual impacts (id.). The Company indicated that short-term environmental impacts, due to construction in and around wetland areas or areas with erodible soils, could be minimized by use of careful construction practices (id.). The Company further indicated that any long-term environmental impacts would be limited to the removal of approximately 7.6 acres of tall-growing vegetation (id.). The Company stated that visual impacts along the primary route would not be significant due to the similarity in height of the new and existing structures, and the vegetative screening that would remain along the majority of the route (id.).

Finally, modifications were made to the design of the primary route in response to abutter concerns (Exh. HO-S-4). The Company stated that it has narrowed the separation between the proposed and existing transmission lines in two areas where residences are located close to the edge of the existing ROW (id.). The Company noted that existing structures will be rebuilt in order to allow the new transmission line to be located as far from residences as possible at two locations: (1) North Street in Andover, which is along the segment unique to the primary route (Figure 2, Segment AB); and (2) West Street in Andover, which is located on the West Andover tap line which is common to both the primary and alternative routes (Figure 2, Segment BC) (id.). The Company further noted that, in both areas, the realignment will allow it to avoid cutting large trees on a number of properties. Additionally, the Company noted that it has agreed to provide several landowners in the North Street area with plantings to install on their own properties for increased screening of the transmission lines, and to install a culvert to alleviate a drainage problem on the ROW in the West Street area (id.).

ii. Alternative Route

The Company indicated that the alternative route also was selected due to its location along an existing utility and railroad corridor (Exh. NEP-6, p. 1-2). After identifying the alternative route, the Company then analyzed environmental, cost and visual impacts of the route (id., pp. 3-8 through 3-12; Exh. HO-S-3). The Company determined that construction of the transmission line along the alternative route would: (1) require complex design and construction practices; (2) result in disruption to traffic; (3) affect businesses and residences adjacent to the railroad corridor; (4) cause significant visual impacts; and (5) traverse a wildlife area (id.). In addition, the Company stated that, due to its location in downtown Lawrence along a railroad ROW without a permanent access road, the cost of constructing and maintaining the proposed facilities along the alternative route would be significantly greater than the cost of construction and maintenance along the primary route (id.).

b. Analysis

The record shows that, as part of its site selection process, the Company identified and evaluated two potential routes for the proposed facilities based on the following criteria: (1) location within existing utility or transportation corridors; (2) consistency with design, construction and cost constraints; and (3) minimization of environmental impacts of construction. Additionally, the Company analyzed the visual impacts of the proposed facilities along each route, although visual impacts were not a consideration included in its initially identified siting criteria. In identifying and evaluating its primary and alternative routes, NEPCo applied its siting criteria in a consistent manner.

Accordingly, the Siting Council finds that NEPCo has applied its site selection criteria consistently and appropriately, in such a manner as to ensure that it has not overlooked or eliminated any siting options which are clearly superior to its proposal.

3. Geographic Diversity

In this section the Siting Council considers the second prong of our practicality test -- whether the Company's site selection process included consideration of route alternatives with some measure of geographic diversity.

The Company stated that in order to meet the Siting Council's geographic diversity requirement, it evaluated two routes for the proposed transmission line, the primary route and the alternative route (Brief, p. 16). The Company acknowledged that the primary and alternative routes are identical for 2.2 miles, or approximately 39 percent, of their distance (id.). NEPCo asserted that the shared portion of the primary and alternative routes was selected because it would enable the Company to use existing steel poles (id., p. 17). However, despite a specific request from the Hearing Officer, the Company did not present any argument regarding whether two routes which are identical for 39 percent of their distance meet the Siting Council's geographic diversity requirement.

The Siting Council's geographic diversity requirement has been discussed in a series of recent cases. In the 1988 Braintree Decision, the applicant proposed to construct two parallel transmission lines and a substation. Relative to the substation, the Siting Council found that the applicant had met the geographic diversity standard because the two substation sites were approximately 750 feet apart and located on two distinct parcels of land. However, the Siting Council also found that the proposed and alternative transmission line routes, which were exactly the same for 72 percent of their length, were not geographically diverse routes. Essentially, the Siting Council reasoned that minor variations in routes were not sufficient to meet the Siting Council's standards regarding geographic diversity (1988 Braintree Decision, 18 DOMSC at 36-40). In a subsequent review of a proposal to construct a cogeneration facility, the Siting Council found that the geographic diversity standard was not met where two different generating facility sites were adjacent to each other and on the same property (Altresco-Pittsfield, 17 DOMSC at 393). In the most recent case examining the geographic diversity issue, the Siting Council reiterated that applicants must provide at least one noticed alternative with some measure of geographic diversity (1990 Berkshire Decision (Phase II), 20 DOMSC at 155).

Historically, the Siting Council has examined the site selection process to determine whether a company has considered a reasonable range of practical alternatives (1988 Middleborough Decision, 17 DOMSC at 197 (1988); 1988 ComElectric Decision, 17 DOMSC at 249). As the practicality standard evolved into a two-prong test, the Siting Council considered whether the two components of the test, site selection and geographic diversity, should be weighted equally. The Siting Council recently has placed greater emphasis on the site selection process as a critical means of ensuring that the petitioner has not overlooked or eliminated any alternative route or site which may be superior to the preferred route or site (1990 Berkshire Decision (Phase II), 20 DOMSC at 153).

In emphasizing the site selection process, the Siting Council also has determined that for proposed cogeneration facilities that meet a particular set of criteria, a geographically diverse alternative does not exist. In such cases, the proponent is not required to identify a geographically diverse site (MASSPOWER, 20 DOMSC at 380; Altresco-Pittsfield, 17 DOMSC at 394). However, in the 1990 Berkshire Facility Decision, in noting that an alternate site is not necessary for certain cogeneration facilities, the Siting Council also stated that:

> [w]hile there may be other situations where a petitioner's site selection process indicates that no practical alternatives exist for the proposed generating facilities, the Siting Council can envision few, if any, instances where such circumstances would exist in gas pipeline and electric transmission line cases (1990 Berkshire Decision Phase II, 20 DOMSC at 155, n.33).

Therefore, even though the Siting Council's emphasis continues to be placed on the site selection process, in electric transmission line and gas pipeline cases, petitioners must still provide a noticed, geographically diverse, alternative route.

In the present case, the Company has provided an alternative route which for 61 percent of its length is geographically diverse from the proposed route. We recognize that there is likely to be some overlap of routes any time an applicant proposes to connect, as is the case here, two fixed points. In this case, based on the difference between the primary and alternative routes, the Siting Council finds that NEPCo's site selection process included consideration of at least two routes with some measure of geographic diversity. We note, too, that the portion of the primary and alternative routes that is identical traverses dense urban and suburban development (Exh. HO-E-2, Photos 1-12, 1-14, 1-16). The only existing utility corridor present in this area is the transmission line ROW which NEPCo proposes to follow under both the primary and the alternate routes (id., Exh. HO-E-16).

In making this finding, the Siting Council notes that it does not accept the Company's argument that the existence of steel poles capable of supporting the proposed transmission line along a portion of this segment justifies the omission of a geographically diverse alternative for this segment. On the contrary, the Company's prior decision to construct poles capable of supporting the proposed transmission line cannot limit its obligation to provide the Siting Council with a geographically diverse alternative.

Further, by determining in this case that the alternative route meets the Siting Council's geographic diversity requirement, the Siting Council does not intend to establish that in all cases the geographic diversity requirement will be satisfied by showing that for 61 percent of their length the proposed and the alternative routes are geographically diverse. Indeed, while establishing a geographic diversity standard which is met by a simple percentage would provide a measure of regulatory certainty, we recognize that setting such a standard would not take into account many different factual situations that may arise in a particular case. Applicants are put on notice that they are well-served by presenting at least one alternative route that is completely different from the proposed route. In the absence of complete geographic diversity between the proposed and the alternative routes, the Siting Council will, on a case-by-case basis, determine whether the facts establish that the routes are sufficiently distinct to meet the geographic diversity standard.

4. Conclusions on Site Selection Process

In order to demonstrate that it has considered a reasonable range of practical siting alternatives, the Siting Council requires a petitioner to demonstrate that (1) it has developed and applied a reasonable set of criteria in making siting decisions, and (2) it has considered alternatives with some measure of geographic diversity.

The Siting Council has found that NEPCo developed a reasonable set of criteria for siting the proposed transmission line. The Siting Council also has found that the Company applied its siting criteria consistently and appropriately in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to its proposal. Additionally, the Siting Council has found that the Company's site selection process included consideration of at least two transmission line routes with some measure of geographic diversity.

Accordingly, the Siting Council finds that NEPCo considered a reasonable range of practical siting alternatives.

D. Cost Analysis of the Proposed and Alternative Facilities

The Company asserted that the primary route is the least cost alternative (Exhs. NEP-6, p. 1-2, HO-C-5, HO-C-6).

The Company presented estimated costs of $1,588,900 in 1988 dollars for construction of the proposed facilities along the primary route (Exhs. NEP-6, p. 2-6, HO-C-5). In addition, the Company presented estimated costs of $2,618,000 in 1988 dollars for construction of the proposed facilities along the alternative route (id.). The following is a breakdown of estimated costs for the primary and alternative routes (in 1988 dollars):

Category	Primary Route	Alternate Route
Material	$532,300	$1,000,000
Construction	657,300	1,170,000
Engineering	170,000	175,000
Permitting	72,900	75,000
Contingency[48]	149,400	180,000
ROW acquisition	7,000	18,000[49]

(Source: Exhs. NEP-6, p. 2-6, HO-C-5).

The Company stated that cost estimates for materials were acquired from vendors, while cost estimates for labor and equipment were derived from recently completed projects of a similar nature (Exh. HO-C-1).

The Company indicated that construction of the transmission line along the alternative route may involve additional costs because the Company could be required to relocate or rebuild the B&M communication and signal system along the railroad ROW, and to build a portion of the transmission line underground due to the narrow width of the ROW at one road crossing (Tr. 3, pp. 63-64, 68). The Company estimated that these additional costs would range from $40,000 to $450,000 per mile for the communication system, and $1,000,000 for underground construction (id., pp. 64-65, 68).

With regard to operation and maintenance costs, the Company indicated that maintenance costs would be greater for the alternative route due to its location on a railroad ROW (Exh. HO-C-5). The Company stated that specialized equipment

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48/ The Company indicated that the category for contingencies would include expenses due to unanticipated problems such as inclement weather and boulders in foundation locations (Tr. 3, pp. 65-67).

49/ In its estimation of costs of the alternative route, the Company included $18,000 for ROW acquisition which is the estimated cost of a license to occupy the B&M ROW for one year (Exhs. HO-C-3, HO-C-5). The Company indicated that the license would have to be renewed annually.

and safety procedures would be required for maintenance along the railroad ROW (Exh. HO-C-6).[50]

Accordingly, based on the Company's analysis of construction and maintenance costs, the Siting Council finds that construction of the proposed 115 kV transmission line along the primary route is preferable to construction along the alternative route with respect to cost.

E. Environmental Analysis of the Proposed and Alternative Facilities

1. Environmental Impacts of the Primary Route

a. Water Resources

The Company provided estimates of wetland impacts for the proposed route (Exhs. HO-E-4, HO-E-5, NEP-6, p. 3-3, NEP-9). While the Company asserted that wetlands were the only water resources which would be affected by construction along the primary route,[51] the Company also indicated that the Town of Andover raised concerns regarding the application of herbicides in areas constituting the watershed of the Town's public water supply system (Exhs. NEP-6, pp. 3-2, 3-3, HO-E-12). Therefore, in its evaluation of impacts of construction of the proposed facilities along the primary route to water resources, the Siting Council considers impacts to wetlands and to the watershed of the Town of Andover's public water supply system.

i. Wetlands

The Company indicated that impacts to wetlands would result from clearing wetland vegetation in order to install

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50/ Specialized equipment and estimated costs are as follows: (1) work train, $2,000 per day; (2) hi-rail boom truck and operator, $500 per day; (3) installation and removal of temporary wood timber rail crossings, $10,000 per day; and (4) inspector and flag crew, $500 per day per crew (Exh. HO-C-6).

51/ The Company stated that no aquifers, public wells or private wells are located within or adjacent to the existing ROW (Exh. NEP-6, p. 3-2).

structures and access roads within wetland areas and managing tall-growing wetland vegetation within the ROW (Exhs. HO-E-5, HO-E-8, NEP-9, NEP-6, pp. 3-3, 3-4). The Company calculated a total of 11,380 linear feet, or 26.2 acres, of wetlands that would be affected by the primary route (Exh. HO-E-4). The Company estimated that 33 poles would be installed within or adjacent to wetland areas, requiring clearing of 88,060 square feet, or 2.02 acres, of wetlands (Exhs. HO-E-4, HO-RR-19, Attachments T-3656-6, T-3658-4, T-3659-3, T-3660-3, T-3661-3, T-3662-3, T-3663-3). The Company further estimated that a maximum of an additional 65,150 square feet, or 1.5 acres, of wetlands might be altered permanently by construction of access roads within the ROW (Exh. NEP-9).

The Company asserted that it considered wetlands impacts in the design of the transmission line (Tr. 3, p. 9).[52] The Company stated that in determining structure locations, it would place structures outside of wetland areas wherever practical (id.). The Company also stated that it would attempt to minimize access roads within wetlands and eliminate waterways crossings by construction vehicles (id., Exh. HO-E-28).

Additionally, the Company asserted that its construction techniques would minimize wetland impacts (Exh. HO-E-6, Tr. 3, pp. 40-60). The Company stated that gravel pads and access roads would be employed to minimize the use of heavy equipment on wetland surfaces (Exh. HO-E-6). The Company noted that access roads would be constructed of either wooden swamp mats or gravel, depending on the conditions within the wetland,[53] and would be designed to take the shortest route from upland locations (Tr. 3, pp. 35-36, 41).

The Company stated that although it plans to negotiate with the appropriate conservation commissions to alter

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52/ The Company also considered visual impacts in determining the location of structures. See Section III.E.1.c, below.

53/ The Company stated that it would place a layer of gravel in shallow wetlands and lay wooden swamp mats in deep wetlands with heavy root growth (Tr. 3, pp. 35-36).

permanently a maximum of 1.5 acres of wetlands for gravel pads and construction of access roads,[54] the entire 1.5 acres may not be altered due to (1) seasonal conditions which might allow construction vehicles to traverse the wetlands,[55] and (2) potential access through abutting properties (Exh. NEP-9; Tr. 3, pp. 51, 53). The Company added that although access to wetlands through abutting properties would be preferable, it would not negotiate with abutters prior to receiving Orders of Conditions from the appropriate Conservation Commissions (Tr. 3, p. 49).

In addition to construction access considerations, the Company indicated that it would utilize specialized construction techniques in order to minimize wetlands impacts (Exh. HO-E-6). The Company stated that it would: (1) cut, dice and leave in place all cleared timber within wetland areas; (2) control siltation of access roadway material; (3) maintain streams and waterways free of debris or slash; (4) restrict refueling of vehicles to upland areas; and (5) set poles in culverts that would be backfilled with clean select material (id.).

In order to maintain the ROW, the Company stated that all vegetation which normally grows to heights of less than 10 feet would be left in its natural condition, but that all species which normally grow to heights greater than 10 feet would not be allowed to revert to natural conditions (Exh. HO-E-5). The Company noted that use of herbicides for vegetation management would be restricted within 10 feet of wetlands (Tr. 2, pp. 96-97). (See Section III.E.1.a.ii, below.)

54/ The Company stated that it prefers to leave the pads and roads in place for future maintenance of the facilities (Tr. 3, pp. 40-41). The record indicates that permanent alteration of wetlands due to pads would be 0.59 acres, and that permanent alteration due to access roads would be 0.91 acres (Exh. NEP-9).

55/ The Company indicated that gravel fill may not be required on access roads if the ground were exceptionally dry or frozen solid (Tr. 3, p. 51). Therefore, due to the amount of wetlands along the route, the Company would prefer to construct during the winter months (id., p. 69).

The record indicates that the primary route traverses a number of wetland areas and that construction of poles and access roads and maintenance of the ROW will permanently alter wetlands along the route. However, in its placement of structures and its plans for construction, the Company has attempted to minimize impacts to wetlands. Where wetlands exist in the vicinity of the route, the appropriate state and local agencies can require mitigation measures under the Wetlands Protection Act to help ensure minimal impact to these areas. The Company also can minimize construction of access roads within sensitive areas by negotiating access with abutters. Finally, use of herbicides is restricted within wetlands.

The Siting Council expects the Company to comply with the requirements of the appropriate Conservation Commissions and to minimize the construction of access roads through wetlands, where feasible, in order to ensure minimal impacts on wetlands resource areas.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route, with the utilization of appropriate mitigation measures in wetland areas, will have an acceptable impact on wetlands.

ii. Herbicides

The Company stated that it would manage tall-growing vegetation on the ROW primarily through selective herbicide treatments which would suppress tree growth but encourage growth of low-growing species (Exh. NEP-5, p. 4). The Company indicated that herbicide treatments are the primary method of vegetation management because use of herbicides greatly reduces tree sprouts and seedlings (id., p. 5). The Company asserted that it would apply herbicides in accordance with federal and state regulations which control all aspects of herbicide application (id., p. 10). In sensitive areas,[56] the Company indicated that it would use specialized vegetation management techniques including (1) hand-cutting; (2) mowing; and (3) use of selected herbicides and/or application techniques in accordance with applicable federal and state regulations (id., p. 7).

The Company noted that the Town of Andover expressed concerns regarding application of herbicides in the area constituting the Haggetts Pond/Fish Brook Watersheds (Exh. HO-E-12).[57] The Company proposed two alternative methods for ROW maintenance in this area: (1) mechanical cutting without application of herbicides; or (2) restrictions on use of herbicides (Exh. HO-E-12, update). However, the Company stated that it would require reimbursement from the Town of Andover for the additional costs it would incur due to mechanical vegetation management (id.). The Company indicated that the Town of Andover agreed to the Company's offer of restricted herbicide use whereby herbicides would be applied with sponges to hardwood stumps only, and conifers, which do not resprout, would be mechanically cut (id.).

The record indicates that the Company will apply herbicides in order to manage tall-growing vegetation on the ROW in a limited and controlled manner and will take additional precautions in sensitive areas. Additionally, the Company is

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56/ Pursuant to federal and state regulations, sensitive areas where herbicide use is restricted include: (1) areas within 400 feet of public water supplies; (2) public water supply recharge areas; (3) areas within 100 feet of private wells; (4) areas within ten feet of wetlands; (5) areas within 300 feet of surface water reservoirs; and (6) areas near surface waters, agricultural areas and residences (Tr. 2, pp. 96-97).

57/ The boundary of the Haggetts Pond/Fish Brook Watersheds, as currently mapped by the Town of Andover, extends generally from the intersection of the existing ROW with Haggetts Pond Road to the intersection of the existing ROW with Chandler Road (Exh. HO-E-12, attachment to February 16, 1990 letter from Harry A. Smith to Donald K. Ellsworth).

willing to further restrict herbicide use in the Haggetts Pond/Fish Brook Watersheds in order to address concerns of the Town of Andover. Based on the foregoing, the Siting Council finds that the Company's use of herbicides will have an acceptable impact on the Fish Brook and Haggetts Pond Watersheds.

iii. Conclusions

The Siting Council has found that construction of the proposed facilities along the primary route would have an acceptable impact on wetlands. In addition, the Siting Council has found that the Company's use of herbicides would have an acceptable impact on the Haggetts Pond/Fish Brook Watersheds. Accordingly, the Siting Council finds that the construction of the proposed facilities along the primary route would have an acceptable impact on water resources.

b. Woodland Clearing

The Company asserted that impacts to woodlands along the primary route would be minimal (Exh. NEP-3, p. 8). The Company stated that although the primary route already has been cleared of most high vegetation, construction would require clearing approximately an additional 7.6 acres of woodlands that would not be allowed to revert to natural conditions (Exh. HO-E-8).[58] The majority of the clearing would take place along the three mile segment of the route from Tewksbury Junction to the West Andover tap where the existing ROW would be cleared of 17 feet of woodland vegetation (id., Exh. NEP-6, Figures 3-2, 3-3, 3-4, 3-5). The existing ROW also would be cleared 17 feet for the 0.2 mile segment from the West Andover tap to the existing double davit steel poles (Tr. 3, p. 25, Exh. NEP-6, Figure 3-3). The Company noted that the West

58/ The Company's estimate of 7.6 acres of woodland clearing does not distinguish between wetland and upland woodland clearing (Exh. HO-E-8). The record indicates that, at most, 3.5 acres of wetlands will be cleared or permanently altered (Exh. NEP-9). Therefore, the Siting Council notes that, at a minimum, 4.1 acres of upland woodlands will be cleared.

Andover tap line was cleared in 1983 to accommodate the construction of a 115 kV transmission and future installation of a second 115 kV transmission line, and construction along this segment therefore only would require some side trimming of tree limbs (Tr. 3, p. 9, NEP-6, Figure 3-5).

The record indicates that along 3.2 miles of the primary route, 17 feet of woodland vegetation would be cleared from the existing ROW and that only side trimming of tree limbs would be required along the remainder of the ROW. All woodland clearing would be directly adjacent to previously cleared areas and no woodlands would be cleared beyond the boundary of the existing ROW.

Accordingly, the Siting Council finds that construction of the proposed facilities along the primary route will have an acceptable impact on land resources.

c. Visual Impacts

The Company asserted that the incremental visual impacts of the proposed facilities along the the primary route would be moderate to low due to the presence of existing electric transmission lines within the ROW (Brief, p. 19; Exh. NEP-6, pp. 3-5, 3-6). The Company indicated visual impacts would be minimized by location and design of the new structures and by vegetative screening that will remain in place along the majority of the route (Exhs. NEP-3, pp. 8-9, NEP-6, pp. 3-5, 3-6; Tr. 3, pp. 60-61).

The Company stated that it attempts to locate new structures alongside existing structures in order to avoid a staggered appearance along the ROW (Tr. 3, pp. 60-61). However, in determining the placement of structures, the Company weighs wetland and visual concerns (id.). The Company stated that although it generally attempts to locate structures outside of wetland areas, it would locate a structure within the border of a wetland in order to locate it adjacent to an existing structure, provided the wetlands impacts were not considered to be significant (id.). The Company further stated that if wetland impacts were determined to be significant, the new structure would be moved away from the existing structure (id., p. 61).

The Company indicated that wetland and visual concerns vary along the route (id., pp. 60-61). The Company stated that wetlands concerns likely would determine structure placement along the segment of the route from Tewksbury Junction to the West Andover tap (Figure 2, segment AB), where the majority of wetlands are located (Tr. 3, p. 60). However, the Company added that this portion of the the ROW is heavily wooded and visual impacts of staggered structures would not be significant (id.). In contrast, the Company identified the segment of the route from the West Andover tap to the double arm steel poles (Figure 2, segment BD) as an area of high visual sensitivity (Tr. 3, p. 61). The Company stated that the ROW traverses a valley adjacent to a new housing development along this portion of the route and that it likely would place greater emphasis on visual concerns in this area (id.).

The Company asserted that design considerations also would minimize visual impacts (Exh. NEP-3, pp. 4-6). The Company indicated that the new structures, like the existing structures, would be constructed of wood (id., p. 4; Exh. NEP-6, p. 3-1). The Company further indicated that the height of the new structures would be similar to the height of existing adjacent structures, ranging from 40 to 75 feet with a typical height of 65 feet (Exh. NEP-3, pp. 4-6). The Company identified nine locations where the heights of new and existing structures could vary by a maximum of ten feet (Exh. HO-RR-17).

Finally, the Company indicated that it agreed to design changes and other mitigation measures in order to reduce visual impacts in specific areas along the route (Exh. NEP-3, pp. 11-12; Tr. 3, pp. 16-17). The Company stated that it agreed to realign existing and proposed transmission lines at the North Street and Webster Street intersections to increase the distance between the proposed transmission line and residences in order to preserve existing vegetation (Exh. NEP-3, pp. 11-12) (see Section III.C.2.a.i, above). Additionally, the Company indicated that it would (1) provide trees for homeowners to plant in order to screen the open areas that will be created by clearing the ROW in the vicinity of the tap point for the West Andover tap line, and (2) increase the span between structures in order to avoid unnecessary impact to a residence at the Haggetts Pond Road crossing located 20 feet from the edge of ROW, and attempt to trim rather than cut large pine trees on the private property at this crossing (Exh. NEP-3, pp. 11-12; Tr. 3, pp. 16-17). Finally, the Company indicated that shrub buffers would be left in place at road crossings, where feasible, to limit the view down the ROW (Exh. NEP-3, p. 9).

The record indicates that the Company considered visual impacts in its design of the proposed facilities and carefully balanced visual and other environmental concerns. The proposed facilities would be constructed adjacent to existing electric transmission lines along an existing ROW and a vegetative screen would be preserved along the majority of the ROW. The new structures would be constructed to the same approximate height and of the same material as existing structures. Wherever possible, the Company would locate new poles adjacent to existing structures. Finally, the Company has agreed to design changes and other measures in order to further reduce visual impacts along specific portions of the route.

Should design plans for the proposed structures change such that (1) structures will not be constructed of wood, or (2) the height of any new structures exceeds the height of adjacent existing structures by more than ten feet, the Siting Council expects that the Company will provide all such information to the Siting Council prior to commencement of construction.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the primary route will have acceptable visual impacts.

d. <u>Electrical Effects</u>

The Company provided an analysis of the impact of the proposed construction of the 115 kV transmission line on the existing electric and magnetic fields along the primary route

(Exhs. HO-E-25, HO-E-36, HO-3, HO-RR-15, HO-RR-16).

The Company calculated the strength of the current magnetic and electric fields within the ROW and at the edge of the ROW for existing peak load conditions without the proposed facilities in place (Exhs. HO-E-25, HO-E-36, HO-RR-15). In addition, the Company calculated the strength of the anticipated electric and magnetic fields within the ROW and at the edge of the ROW for existing and 1997 peak load conditions with the proposed facilities in place (id., Exh. HO-RR-16). The Company measured the magnetic and electric fields at one meter above ground for each configuration of the existing and proposed facilities along the primary route (Exhs. HO-E-25, HO-E-36, HO-RR-15) (See Table 3).

With regard to magnetic fields, the Company's analysis demonstrates that the installation of the proposed facilities would reduce the existing magnetic fields within the ROW along the entire length of the primary route (id.). The reduction would occur under both the existing and 1997 peak load conditions (id., Exh. HO-RR-16).

In addition, the Company's analysis demonstrates that the installation of the proposed facilities would reduce the existing magnetic fields at the edge of the ROW for all segments of the primary route under existing peak load conditions (Exhs. HO-E-25, HO-E-36, HO-RR-15). Under anticipated 1997 peak load conditions, the magnetic fields would be reduced at the edge of the ROW for all segments of the primary route with the exception of the West Andover tap line (Figure 2, Segment BC) (id., Exh. HO-RR-16).

The Company's analysis further demonstrates that the segment of the route with the highest existing and expected magnetic fields is the segment from the West Andover tap to the double arm steel poles (Figure 2, Segment BD) (id.). The existing magnetic field strength in this section, within the ROW, is 22.12 milligauss while the field strength at the edge of the ROW is 14.42 milligauss (Exh. HO-RR-15).[59] With the addition of the proposed facilities, magnetic fields within the ROW and at the edge of the ROW are estimated to decrease to (1) 14.42 and 3.88 milligauss, respectively, for current peak load conditions, and (2) 16.59 and 4.46 milligauss, respectively, for 1997 peak load conditions (id.).

The Company explained that the reduction in magnetic field strength in all segments of the primary route would result primarily from a reduction in current flowing in the existing 115 kV transmission line due to sharing of current with the new line (Exh. HO-E-27). The Company added that the arrangement of the phases of the new transmission line, relative to the phase arrangement on the existing transmission lines also would be a significant factor in the reduction of magnetic field strength (id.).[60]

With regard to electric field strengths, the Company's analysis demonstrates that the addition of the proposed facilities generally will cause a decrease in electric field strength within the ROW and an increase in electric field strength at the edge of the ROW (Exhs. HO-E-25, HO-E-36, HO-RR-15, HO-RR-16).[61] The Company's analysis further

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59/ Magnetic fields are slightly higher within the ROW at the North Street intersection, which is within the segment of the route from Tewksbury Junction to the West Andover tap (Figure 2, Segment AB) (Exh. HO-E-36). The Company indicated that the higher magnetic field result from the decreased distance between the existing and proposed lines (Tr. 2, pp. 69-70). For current peak load conditions, magnetic fields within the ROW are calculated to be 15.08 milligauss with the proposed facilities in place (Exh. HO-E-36).

60/ The Company explained that additional design considerations that would affect the strength of magnetic fields are conductor configuration, conductor height above ground and conductor distance from the edge of the ROW (Exh. HO-E-27).

61/ The Company's analysis indicated that there is one segment of the route -- the segment of the ROW with the double arm steel poles (Figure 2, Segment DE) -- where the addition of the proposed facilities would decrease the strength of the electric field both within the ROW and at the edge of the ROW (Exh. HO-E-25).

demonstrates that increased load in 1997 will not affect electric field strengths (id., HO-E-16).

The Company's analysis indicates that the West Andover tap line (Figure 2, segment BC) is the segment of ROW where electric field strengths within the ROW would be greatest with the addition of the proposed facilities (Exh. HO-E-25, HO-E-36, HO-RR-15). Along this segment, with the addition of the proposed facilities, the electric field strengths decrease from 0.693 to 0.605 kV/meter within the ROW (id.).

The Company's analysis further demonstrates that the segment of the route from the West Andover Tap to the double arm poles (Figure 2, Segment BD) is the segment of the ROW where the electric field strength at the edge of the ROW would be greatest with the addition of the proposed facilities (id.). Along this segment, with the addition of the proposed facilities, the electric field strengths increase from 0.112 to 0.335 kV/meter at the edge of the ROW (id.).

The Company stated that it considered all factors affecting the strength of electric and magnetic fields,[62] as well as aesthetics and economics, in the design of the transmission line (id.). The Company further stated that in situations where there may be specific concerns with fields and their effects, it would consider possible adjustment, within the physical constraints of the location, to reduce field levels (Tr. 2, p. 78). However, the Company noted that it does not consider the reduced magnetic fields resulting from the proposed project to be an environmental benefit of the project (id., pp. 78-79).

In our review of the Hydro Quebec project, which included 450 kV direct current and 345 kV alternating current

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62/ The Company explained that electric fields are generally increased by the addition of a new transmission line to a ROW, but can be reduced by various methods including: (1) use of lower voltage facilities; (2) increasing the height of conductors above the ground; (3) moving conductors away from the edge of the ROW; and (4) installing the line underground (Exh. HO-E-27). The Company added that lower voltage lines with the same MVA rating would produce higher magnetic fields (id.).

transmission facilities, the Siting Council addressed in detail the expected electrical effects of such facilities, notably the health implications of electric and magnetic fields. 1985 MECo Decision, 13 DOMSC at 228-242. In that case the petitioner estimated that the electric field would not exceed 1.8 kV/m, and that the magnetic field would not exceed 85 milligauss, along the edge of the 345 kV rights-of-way. Id., pp. 228-229. The Siting Council found those edge-of-right-of-way field levels to be acceptable. Id., p. 241.

In the instant case, the expected levels of electric and magnetic fields within the ROW and at the edge of the ROW for existing peak load conditions and estimated 1997 peak load conditions are well below the levels accepted by the Siting Council after detailed review of the Hydro Quebec project.

In addition, the Company indicated that it will arrange the phasing on the proposed transmission line, relative to the phase arrangement on the existing line in a manner which will reduce the strength of magnetic fields along the entire route.

Accordingly, based on this record, the Siting Council finds that the expected electrical effects of the proposed facilities along the primary route are acceptable.

2. Environmental Impacts of the Alternative Route

a. Water and Land Environments

The Company provided estimates of impacts to water and land resources of the construction of the proposed facilities along the alternative route including wetlands crossing, woodland clearing and the crossing of an aquifer (Exhs. HO-E-4, HO-E-5, HO-E-8, HO-E-24, NEP-6, pp. 3-8, 3-9, 3-10, 3-12).

With respect to wetlands, the Company asserted that potential impacts would result primarily from clearing wetland vegetation in order to install structures and access roads within wetland areas and from managing tall-growing wetland vegetation within the ROW (Exh. NEP-6, p. 3-9).

The Company indicated that 2,540 linear feet or 5.7 acres of wetlands are located within the portion of the ROW that is common to both the primary and alternative routes (Exh. HO-4).

The Company estimated that ten structures would be installed within this portion of ROW, which would require clearing approximately 0.4 acres of wetlands (Exhs. HO-E-5, HO-RR-19, Attachments T-3661-3, T-3662-3, T-3663-3).

The Company indicated that there are additional wetlands along the alternative route associated with the Nevins Wildlife Area which is a relatively flat, wooded wetland with a small pond, and the Spickett River which crosses the Nevins Wildlife Area in the vicinity of the alternative route (Exhs. HO-E-4, HO-E-16, HO-E-24).[63] The Company estimated that seven structures would be installed along the existing electric transmission line ROW and existing railroad ROW within the Nevins Wildlife Area, but noted that it had not yet performed a field survey in order to accurately determine the limits of these wetlands (Exhs. HO-E-4, HO-RR-19, Attachments T-3317-4, T-3236-2). The Company stated that, although there is an existing access road into the Nevins Wildlife Area, individual structure installation may require additional access roadways or swamp matting (Exh. HO-E-24).

With regard to impacts to woodlands, the Company indicated that approximately 1.4 acres of woodlands would require clearing along the alternative route (Exhs. HO-E-8, NEP-6, p. 3-10). The majority of the clearing, 1.0 acres, would take place within the Nevins Wildlife Area where 30 to 56 feet of vegetation would be cleared from the eastern edge of the ROW (Exhs. HO-E-8, NEP-6, Figure 3-8). The Company noted that specialized construction techniques would be utilized in order to clear trees in the Nevins Wildlife Area (id.). The Company would fell trees without the use of machinery and would then dice trees and leave them in place to decompose (id.). The

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63/ The Company indicated that the portion of the alternative route that would cross the Nevins Wildlife Area is (1) the 0.2 mile segment from its starting point at Methuen Junction to its intersection with the B&M railroad tracks, (Figure 3, Segment FG), and (2) the segment that includes the first three structures within the railroad ROW (Figure 3, Segment EF) (Exhs. HO-RR-19, Attachments T-3317-4, T-3236-2 NEP-6, p. 3-7).

Company added that 0.4 acres of forested vegetation would be cleared from the portion of the route that is common to the primary route and noted that some side trimming would be required and individual trees would require removal along the B&M railroad tracks (Exh. NEP-6, p. 3-10).

Additionally, the Company asserted that construction along the alternative route potentially could affect wildlife habitat within wetlands (Exh. NEP-6, p. 3-12). The Company indicated that the Nevins Wildlife Area is a bird sanctuary and that the pond located within the area provides nesting habitat for the great blue heron (id.).

Finally, the Company stated that a potential impact to water resources would result from the crossing of an aquifer by the alternative route (Exh. NEP-6, p. 3-8). The Company indicated that the aquifer extends along both shorelines of the Merrimack River, but did not provide information regarding the number of structures that would be installed within the aquifer and the effect that such construction would have on the aquifer (id.). The United States Geological Survey map of the Lawrence Quadrangle indicates this aquifer is located within an urban area where a number of existing structures already are located (Exh. HO-E-16).

The record indicates that the alternative route would traverse 0.7 miles of wetlands, including slightly more than 0.2 miles of wetlands associated with the Nevins Wildlife Area and Spickett River.

Approximately seven structures would be installed within the vicinity of the Nevins Wildlife Area and approximately 1.0 acres of woodlands would be cleared within this area. Although the Company has not determined the full extent of the wetlands that would be altered due to installation of structures and related construction of access roads, the Company indicated that it would utilize specialized construction techniques. In addition, an electric transmission line ROW, a railroad ROW and an access road already exist within the area. Further, the Company would be required to comply with the mitigation measures of the Methuen Conservation Commission and seasonal construction considerations likely would minimize impacts to wildlife nesting within the area. However, application of herbicides within the Nevins Wildlife Area would be a potential concern.

The record indicates that construction of the alternative route would require minimal woodland clearing outside the Nevins Wildlife Area.

The record further indicates that the alternative route would cross an aquifer in the vicinity of the Merrimack River. Although the Company has not provided information regarding the number of structures that would be installed within the aquifer, the aquifer is located within an urban area and a number of structures already exist within the vicinity of the aquifer.

Based on the foregoing, the Siting Council finds that the construction of the proposed facilities along the alternative route would have an acceptable impact on water and land environments.

b. Visual Impacts

The Company asserted that incremental visual impacts of the proposed facilities along the alternative route would be significant due to the: (1) location of the route in downtown Lawrence; (2) height requirements of the new structures; and (3) lack of significant vegetative screening along the majority of the route (Exhs. NEP-3, pp. 15-16, NEP-6, p. 3-11).

The Company indicated that the 3.1-mile portion of the alternative route which would be constructed within the existing B&M railroad ROW which traverses downtown Lawrence (Figure 3, Segment EF) (Exh. NEP-6, p. 3-9). The Company stated that new structures along this portion of the route generally would be twice as high as existing structures (id., p. 3-11, Figures 3-9, 3-10, 3-11).

The Company indicated that the structures supporting the existing 23 kV line along this portion of the alternative route are approximately 40 to 50 feet high and that new structures would be approximately 80 to 100 feet high (id., Figures 3-9, 3-10, 3-11).[64] The Company noted that high density residential areas abut the existing B&M railroad line ROW with minimal or no vegetative buffer and that visual impacts therefore would be increased significantly for a large number of residential viewers (Exh. NEP-3, p. 16).

In addition, the Company stated that 100-foot high H-frame structures would be required in order to span the Merrimack River in downtown Lawrence (id., p. 16-17). The Company noted that the vicinity of the Merrimack River crossing is completely open to view, and that the visual impact of the structures to downtown Lawrence would be severe (id.).

The record indicates that new structures ranging in height from 80 to 100 feet would be installed within residential areas of Lawrence as well as downtown Lawrence. Although electric transmission line structures already exist along the railroad ROW where the alternative route would be constructed, the new structures would be twice as high as existing structures. Further, there is minimal or no vegetative buffer along the existing ROW. Thus, the new structures would be seen for greater distances and have a significantly greater impact than the existing electric transmission line structures to the downtown Lawrence area as well as the densely populated residential areas along the route.

Based on the foregoing, the Siting Council concludes that construction of the proposed facilities along the alternative route would have unacceptable visual impacts.

c. Electrical Effects

The Company provided an analysis of the effect of the proposed construction of the 115 kV transmission line on the

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64/ The Company indicated that increased pole height will be required in order to underbuild the existing 23 kV line on the same structures that will support the proposed 115 kV line (Exh. NEP-5, p. 15).

existing electric and magnetic fields along the alternative route (Exhs. HO-E-25, HO-3, HO-RR-15).

The Company calculated the strength of the magnetic and electric fields within the ROW and at the edge of the ROW for existing peak load conditions without the proposed facilities in place (Exhs. HO-E-25, HO-RR-15). In addition, the Company calculated the strength of anticipated electric and magnetic fields within the ROW and at the edge of the ROW for existing peak load conditions, with the proposed facilities in place (id.). The Company measured the magnetic and electric fields at one meter above ground for each configuration of the existing and proposed facilities along the alternative route (id.) (See Table 4).

As previously noted, the major portion (3.1 miles) of the alternative route would be constructed within the B&M railroad ROW (Figure 3, Segment EF) (Exh. NEP-6, p. 3-7). The Company's analysis demonstrates that for two of the three configurations of facilities along this portion of the route, the strength of the magnetic fields would decrease and the strength of the electric fields would remain unchanged (Exhs. HO-E-25, HO-RR-15).

The Company's analysis further demonstrates that the strength of the magnetic and electric fields are highest along the portion of the alternative route from Methuen Junction to the intersection with the B&M railroad tracks (Figure 3, Segment EF) both with and without the proposed facilities (Exhs. HO-E-25, HO-RR-15). Along this portion of the ROW, the Company's analysis demonstrates that the strength of magnetic and electric fields would increase with the addition of the proposed facilities (id.). At the edge of the ROW, the strength of the magnetic fields would increase from 20.07 milligauss to 20.49 milligauss, and the strength of the electric fields would increase from 0.063 to 0.570 kV/meter (id.).

The record indicates that expected levels of electric and magnetic fields within the ROW and at the edge of the ROW for existing peak load conditions are well below the levels that were accepted by the Siting Council after detailed review of the Hydro Quebec project. (See Section III.E.1.d, above.) Accordingly, based on this record, the Siting Council finds that the expected electrical effects of the proposed facilities along the alternative route are acceptable.

3. Conclusions on Environmental Impacts

The Siting Council has found that the construction of the proposed facilities along the primary route would have an acceptable impact on water and land resources as well as acceptable visual and electrical impacts.

The Siting Council has found that construction of the proposed facilities along the alternative route would have an acceptable impact on water and land resources and that the electrical effects of the proposed facilities along the alternative route are acceptable. However, the Siting Council also has found that the proposed facilities along the alternative route would have unacceptable visual impacts.

The record demonstrates that the most significant environmental impact of the primary route would be permanent alteration of wetlands located along the route. However, these wetland impacts can be sufficiently minimized through mitigation measures and specialized construction techniques.

The record demonstrates that the most significant impact of the alternative route on water resources also would be the permanent alteration of wetlands located along the route, and in particular, wetlands associated with the Nevins Wildlife Area and Spickett River in Methuen. The record further demonstrates that construction within the Nevins Wildlife Area could potentially interfere with wildlife nesting. However, the alternative route would cross a short distance of the wildlife area and the impact can be minimized through mitigation measures, timing of construction and construction techniques.

In sum, a comparison of the two routes indicates that construction of the proposed facilities along the primary route would affect a greater number of wetlands than construction along the alternative route. However, construction along the alternative route would affect wetlands of greater sensitivity due to the presence of a wildlife habitat within the affected wetlands.

Accordingly, the Siting Council finds that construction of the proposed facilities along the primary and alternative route would be comparable in regard to water resources.

The record demonstrates that the most significant environmental impact of the primary route on land resources would be the clearing of woodland vegetation along the route. However, all clearing of woodland vegetation would take place within the existing ROW.

The record demonstrates that construction of the alternative route also would require clearing of woodland vegetation. Woodland clearing would take place primarily within the Nevins Wildlife Area but the the Company would utilize specialized construction techniques within this area.

A comparison of the routes indicates that construction of the proposed facilities along the primary route would require a greater amount of woodland clearing than construction along the alternative route. However, construction along the alternative route would affect woodlands of greater sensitivity.

Accordingly, the Siting Council finds that construction of the proposed facilities along the primary and alternative routes would be comparable in regard to land resources.

The record demonstrates that construction of the proposed facilities along the primary route would have acceptable visual and electrical impacts. The record further demonstrates that construction of the proposed facilities along the alternative route would have acceptable electrical impacts. However, the visual impacts of the alternative route would be significant due to its location in downtown Lawrence due to the substantial increase in the height of the proposed structures in relation to existing structures and the lack of significant vegetative screening along the majority of the route.

Accordingly, the Siting Council finds that construction of the proposed facilities along the primary route would be comparable to construction along the alternative route in regard to electrical impacts but would be preferable to construction along the alternative route in regard to visual impacts.

Based on the foregoing, the Siting Council finds that, on balance, the primary route is preferable to the alternative route with respect to environmental impacts.

F. Reliability Analysis of the Proposed and Alternative Facilities

The Company compared the reliability of construction of the proposed facilities along the primary and alternative routes with regard to the likelihood of outages caused by vehicle damage and lightning (Exh. HO-R-1). The Company asserted that any fault on either the preferred or alternative route would not interrupt any customer load (id.).

With regard to likelihood of outages from vehicle damage, the Company concluded that the potential risk to both routes would be negligible due to the location of both routes along existing ROWs rather than along public streets (id.). However, the Company added that the risk of such an outage is slightly greater for an 825 foot segment of the alternative route due to its location adjacent to a public way in Methuen (id.).

The Company further stated that the likelihood of lightning outages would be higher along the primary route than along the alternative route (id.). The Company stated that design components affecting protection from lightning strokes, including shielding and insulation level, would be comparable for transmission lines along either route (id.). However, the Company noted that the distance between fault clearing devices (circuit breakers) would be greater for the primary route and therefore would result in a greater potential for lightning outages (id.).

The record indicates that the risk for vehicle damage to the proposed facilities would be greater along the 825 foot portion of the alternative route. The record further indicates that the risk for lightning outage of the proposed facilities would be greater along the entire primary route.

Based on the foregoing, the Siting Council finds that construction of the proposed facilities along the alternative route would be slightly preferable to the primary route in regard to reliability.

G. Conclusions on the Proposed and Alternative Facilities

The Siting Council has found that the Company considered a reasonable range of practical alternatives.

In addition, the Siting Council has found that construction of the proposed facilities along the primary route is preferable to construction along the alternative route with respect to cost and environmental impacts. Finally, the Siting Council has found that construction of the proposed facilities along the alternative route would be slightly preferable to construction of the proposed facilities along the primary route with respect to reliability. Accordingly, the Siting Council finds that the primary route is, on balance, preferable to the alternative route.

However, in order to ensure that the Company's proposal is implemented in a manner consistent with the Siting Council's standard that there be a minimum impact on the environment, the Siting Council ORDERS NEPCo to:

1. Minimize permanent alteration of wetland areas to the greatest extent possible. To this end, NEPCo shall attempt to acquire necessary easements or permission from landowners for right of access to the ROW across property abutting the ROW where such access would avoid installation of gravel pads or construction of access roads within wetlands. NEPCo shall prepare a preliminary report, prior to requesting Orders of Conditions from the appropriate Conservation Commissions,

detailing: (1) the locations where access rights across abutting property would avoid construction within wetlands; (2) the results of initial inquiries; and (3) the status of any negotiations with property owners concerning such access rights. NEPCo shall submit this report to the Siting Council, and upon verification by the Siting Council staff that the report fully satisfies this condition, NEPCo shall use the report as a basis for its request for Orders of Conditions from the appropriate Conservation Commissions.

2. Manage tall-growing vegetation within the Haggetts Pond/Fish Brook watershed in the Town of Andover (as mapped by the Town of Andover in Exh. HO-E-12, attachment to February 16, 1990 letter from Harry A. Smith to Donald K. Ellsworth) by (1) mechanical cutting of conifers; and (2) mechanical cutting or sponge application of herbicides to hardwoods.

3. Construct the proposed facilities, in conjunction with the appropriate switching adjustments to the 115 kV system, in strict conformance with all aspects of its proposal with the Siting Council. In the case of changes, other than minor variations, the Company is required to file that information with the Siting Council, prior to the commencement of construction, so that the Siting Council may ascertain whether construction of the proposed facilities would be in strict conformance with the Company's proposal.

IV. DECISION AND ORDER

The Siting Council finds that construction of a 5.7-mile 115 kilovolt electric transmission line along the primary route, in conjunction with appropriate switching adjustments to the 115 kV system, is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Council hereby APPROVES the petition of New England Power Company to construct a 5.7-mile 115 kilovolt electric transmission line along the primary route, in conjunction with appropriate switching adjustments to the 115 kV system.

Further, the Siting Council ORDERS NEPCo to

1. Minimize permanent alteration of wetland areas to the greatest extent possible. To this end, NEPCo shall attempt to acquire necessary easements or permission from landowners for right of access to the ROW across property abutting the ROW where such access would avoid installation of gravel pads or construction of access roads within wetlands. NEPCo shall prepare a preliminary report, prior to requesting Orders of Conditions from the appropriate Conservation Commissions, detailing: (1) the locations where access rights across abutting property would avoid construction within wetlands; (2) the results of initial inquiries; and (3) the status of any negotiations with property owners concerning such access rights. NEPCo shall submit this report to the Siting Council, and upon verification by the Siting Council staff that the report fully satisfies this condition, NEPCo shall use the report as a basis for its request for Orders of Conditions from the appropriate Conservation Commissions.

2. Manage tall-growing vegetation within the Haggetts Pond/Fish Brook watershed in the Town of Andover (as mapped by the Town of Andover in Exh. HO-E-12, attachment to February 16, 1990 letter from Harry A. Smith to Donald K. Ellsworth) by (1) mechanical cutting of conifers; and (2) mechanical cutting or sponge application of herbicides to hardwoods.

3. Construct the proposed facilities, in conjunction with the appropriate switching adjustments to the 115 kV system, in strict conformance with <u>all</u> aspects of its proposal with the Siting Council. In the case of changes, other than minor variations, the Company is required to file that information with the Siting Council, prior to the commencement of construction, so that the Siting Council may ascertain whether construction of the proposed facilities would be in strict conformance with the Company's proposal.

Sue Nord

Sue Nord
Hearing Officer

Dated this 17th day of May, 1991.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of May 17, 1991 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Paul W. Gromer (Commissioner of Energy Resources); Penelope Wells (for Gloria Larson, Secretary of Consumer Affairs and Business Regulation); Andrew Greene (for Susan Tierney, Secretary of Environmental Affairs); Joseph Faherty (Public Labor Member); Mindy Lubber (Public Environmental Member); and Michael Ruane (Public Electricity Member).

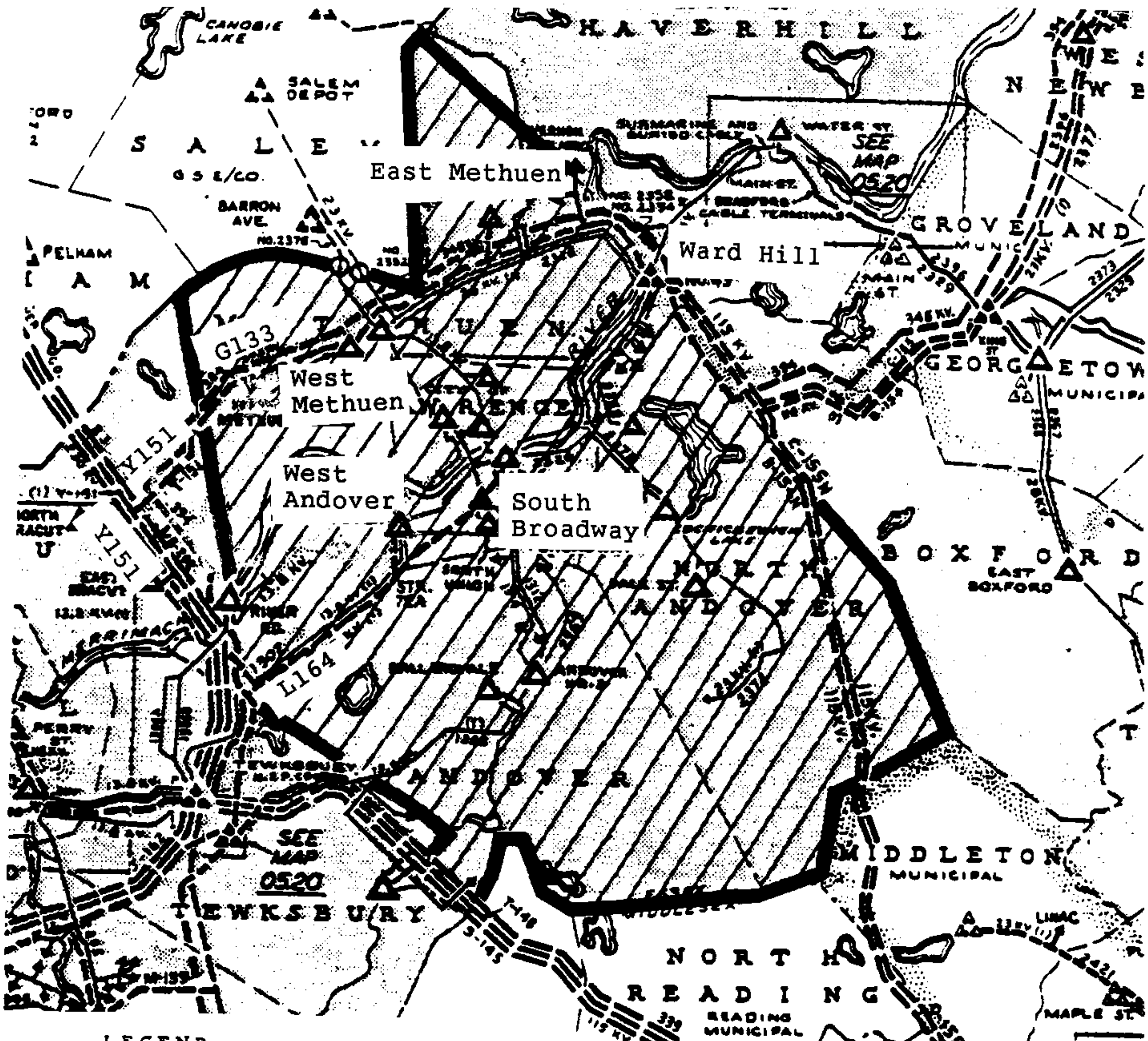
Paul W. Gromer
Chairperson

Dated this 17th day of May, 1991

4410H

Figure 1

Location of the Major Electrical Facilities
in the Lawrence Area



LEGEND

- ▲ Transmission Substations
- △ Distribution Substations
- Hydro - Electric Plants
- Steam - Electric Plants
- Nuclear Plant
- Diesel - Electric Plants
- Transmission Lines
- Points of Interconnection on Lines
- Distribution System Supply Lines
- Distribution Lines
- ⊕ Scheduled for Coming Year or Under Construction
- Connections to Industrial Customers

- △—— Property of Massachusetts Electric Company
- △-- -- Property of other electric companies of N.E.E.S.
- △-- -- Property of other interconnecting companies

SERVICE AREA AND PROPERTY

MASSACHUSETTS ELECTRIC COMPANY

IN NORTHEASTERN PORTION OF MASSACHUSETTS

NEW ENGLAND POWER COMPANY

115 kV TRANSMISSION ADDITIONS TO SUPPLY WEST ANDOVER AND SOUTH BROADWAY SUBSTATIONS

ELECTRIC FACILITIES MAP LAWRENCE SUPPLY AREA

APRIL 1989

MAIN 1893

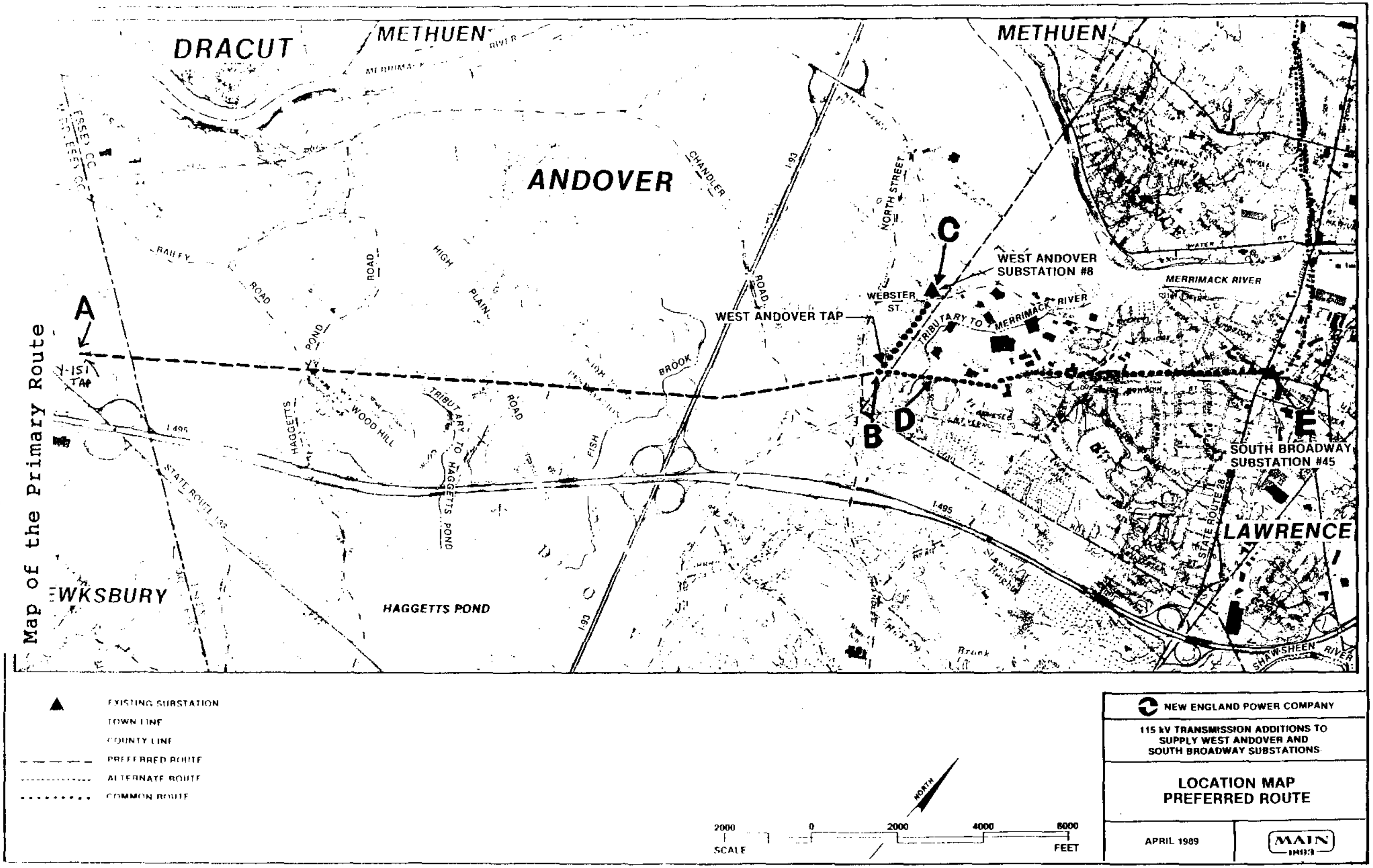


Figure 2
Map of the Primary Route

Figure 3

Map of the Alternative Route

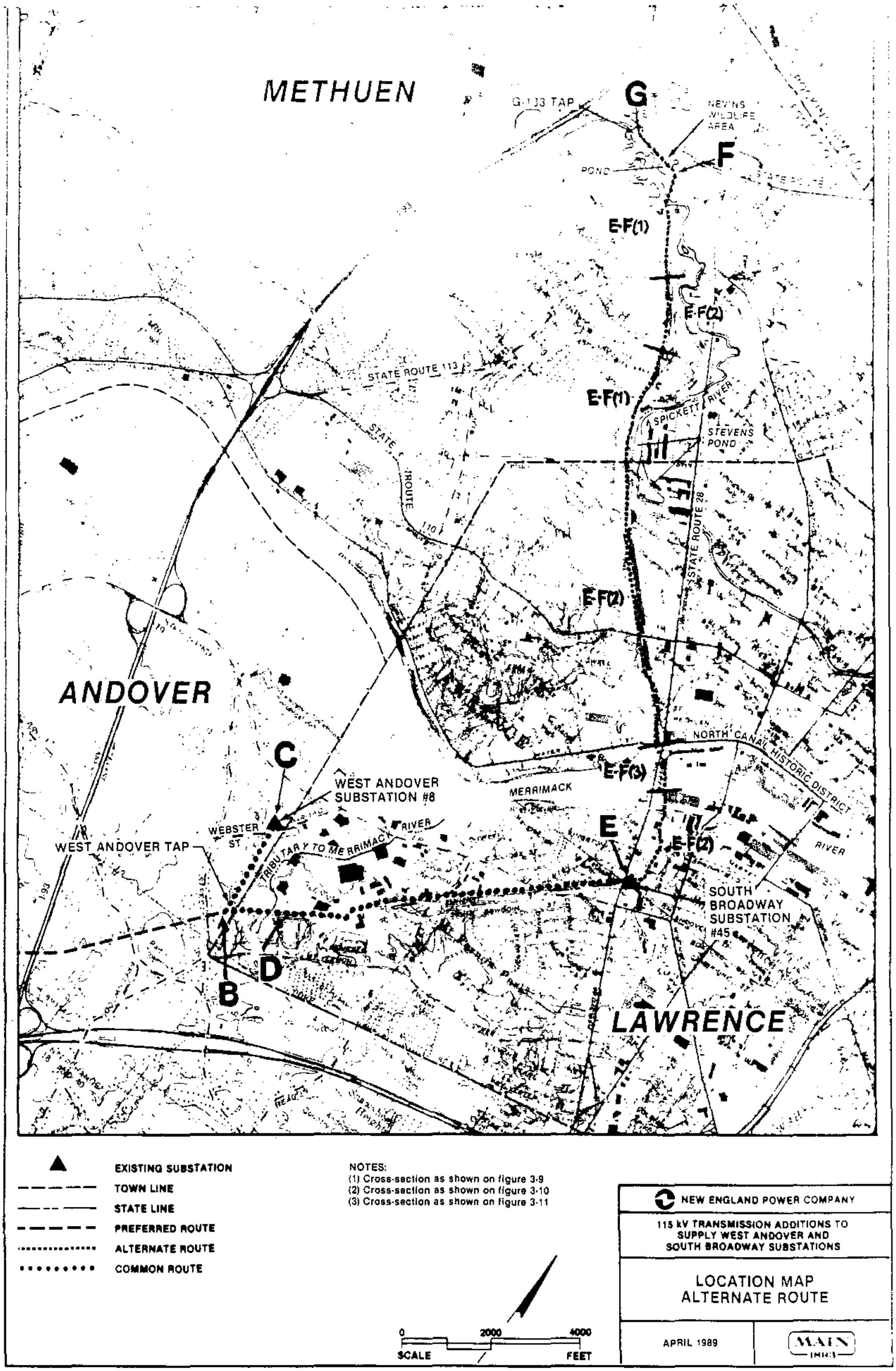


Table 1

New England Power Company
Summer Peak Load Forecast (MW)
Merrimack PSA, Lawrence Area

	Merrimack PSA			Lawrence Area	
	1989 Forecast	1991 Forecast Update		1989 Forecast	1991 Forecast Update
Year	Base Case	High Case	Base Case	Base Case	
1989	821	790	790[a]	278[b]	
1990	843	771	771	283	286[c]
1991	865	802	733	289	298
1992	888	831	732	301	308
1993	903	859	769	313	319
1994	926	886	806	319	329
1995	948	915	842	325	339
1996	977	945	864	336	
1997	1013	970	884	347	

Notes:

a. Actual 1989 peak load, Merrimack PSA
b. Actual 1989 diversified peak load, Lawrence Area
c. Actual 1990 diversified peak load, Lawrence Area

Sources: Exhs. NEP-2, attachment RHS-4, HO-RR-2, HO-N-37b,c

Table 2

New England Power Company
Summer Peak Load Forecast (MW)
West Andover Substation

	1989 Base Forecast			1991 Forecast Update		
Year	13.2 kV	34.5 kV	Total	13.2 kV	34.5 kV	Total
1989	9.8	21.2	31.0[a]			
1990	12.2	21.5	33.7	12.0	21.5	33.5[b]
1991				13.0	23.4	36.4
1992	14.5	23.3	37.8	13.2	24.0	37.2
1993				13.6	24.9	38.5
1994				16.0	26.7	42.7
1995				17.0	28.5	45.5
1997	19.0	28.5	47.5			

Note:

a. Actual 1989 diversified peak load.
b. Actual 1990 diversified peak load.

Sources: Exhs. HO-N-23d, NO-N-37c

Table 3

Magnetic and Electric Field Strengths along the Primary Route

Magnetic Field Strengths (milligaus)

Route Segment	Current Conditions	Proposed Facilities 1990 peak load	Proposed Facilties 1997 peak load
Within ROW			
A-B	22.11	14.41	16.59
B-C	10.15	3.46	3.96
B-D	22.12	14.42	16.59
D-E	9.14	2.59	2.97
North St	22.11	15.08	
Webster	10.15	3.46	
Edge of ROW			
A-B	4.53	2.73	4.46
B-C	1.87	1.46	2.22
B-D	4.62	3.88	4.46
D-E	8.33	2.11	2.42
North	4.53	3.25	
Webster	1.87	1.27	

Electric Field Strengths (kV/meter)

Within ROW			
A-B	.540	.436	.436
B-C	.693	.605	.605
B-D	.542	.439	.439
D-E	.359	.144	.144
North	.540	.555	
Webster	.693	.605	
Edge of ROW			
A-B	.082	.290	.290
B-C	.133	.299	.299
B-D	.112	.355	.335
D-E	.282	.132	.132
North	.082	.227	
Webster	.133	.260	

Sources: Exhs. HO-E-25, HO-E-36, HO-RR-3, HO-RR-15, HO-RR-16

Table 4

Magnetic and Electric Field Strengths along the Alternative Route

Magnetic Field Strengths (milligaus)

Route Segment	Current Conditions	Proposed Facilities 1990 Peak Load
Within ROW		
FG	25.09	27.03
EF (1)	10.76	2.24
(2)		9.48
(3)	10.76	2.24
Edge of ROW		
FG	20.07	20.49
EF (1)	10.63	2.21
(2)		8.84
(3)	10.63	2.21

Electric Field Strengths (kV/meter)

Route Segment	Current Conditions	Proposed Facilities 1990 Peak Load
Within ROW		
FG	.087	.642
EF (1)	.046	.046
(2)		.061
(3)	.046	.046
Edge of ROW		
FG	.063	.570
EF (1)	.045	.045
(2)		.056
(3)	.045	.045

Sources: Exhs. HO-E-25, HO-RR-15

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of services of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (See. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).