Decision and Orders

Massachusetts Energy Facilities Siting Council

VOLUME 23

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PUBLICATION 17119-459-100-5-92
APPROVED BY: PHILMORE ANDERSON, STATE PURCHASING AGENT

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Enron Power Enterprise Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSC 90-101

FINAL DECISION

Michael D. Ernst
Hearing Officer
August 29, 1991

On the Decision:

Robert Graham
Sue Nord

William Febiger
Robert J. Harrold
JoAnne Pierce
Barbara Shapiro
Timothy Y. K. Wang

APPEARANCES: Edward L. Selgrade, Esq.
Tillinghast, Collins & Graham
303 Congress Street, 5th Floor
Boston, Massachusetts 02110
FOR: Enron Power Enterprise Corporation
Petitioner

Karen Pelto
Charles River Watershed Association
2391 Commonwealth Avenue
Auburndale, Massachusetts 02166
FOR: Charles River Watershed Association
Pro Se
Intervenor

Margaret A. Knowlton
Lena McCarthy
14 Chestnut Street
Milford, Massachusetts 01757
FOR: Concerned Citizens Against Pollution
Pro Se
Intervenor

Kathleen Tosches
57 Beach Street
Milford, Massachusetts 01757
Pro Se
Intervenor

William A. Murray, Esq.
260 Main Street
Milford, Massachusetts 01757
FOR: Joanne Tusino
Intervenor

Lee G. Ambler, Esq.
Six Mendon Street
Bellingham, Massachusetts 02019
FOR: Town of Bellingham
Intervenor

John C. Traficonte, Esq.
Distrigas of Massachusetts Corporation
200 State Street
Boston, Massachusetts 02109
FOR: Distrigas of Massachusetts Corporation
Interested Person

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Attachment A: Town of Milford Zoning Board of Appeals Special Permit for the Proposed Project

The Energy Facilities Siting Council hereby APPROVES the petition of Enron Power Enterprise Corporation to construct a 146 megawatt bulk electric generating facility in Milford, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Enron Power Enterprise Corporation ("EPEC") has proposed to construct a 146 megawatt ("MW")[1] gas-fired, combined cycle, independent power production ("IPP") facility on a 6.8-acre[2] industrially zoned site in the Town of Milford, Massachusetts (Exh. EPEC-19, pp. 2-1, 2-2).[3] The proposed facility would be fueled solely by liquefied natural gas ("LNG") that would be provided by Distrigas of Massachusetts Corporation ("DOMAC") (Exh. EPEC-1, p. I-47). Algonquin Gas Transmission Company ("Algonquin") would construct a new 3.1-mile natural gas pipeline and meter station to transport

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1/ EPEC's initial petition stated that the proposed facility would generate 140 MW of power (Exh. EPEC-1, p. I-20). EPEC later stated that it planned to operate the facility to produce no more than an average of 146 MW of electricity over the course of a year, although the average annual net design capacity of the plant at full operation, also known as the nominal rating, would be 161.1 MW (Exh. HO-RR-74). Therefore, the analysis and findings in this case are based on operation of the proposed facility at 146 MW. In the future, the Siting Council expects the developer of a jurisdictional generation facility to state in the initial petition the accurate design output of the generating equipment proposed for use in the facility.

2/ EPEC originally stated that the primary site would be 4.4 acres (Exh. EPEC-1, p. I-28). EPEC later explained that it had purchased an additional 2.4 acres of land adjacent to the original primary site to total 6.8 acres (Exh. EPEC-19, p. 2-1).

3/ See Figure 1 for a map of the primary generating facility site and utility line routes.

gas to the proposed facility (Exh. HO-PV-34).[4]

EPEC's petition includes a proposal to construct the generating facility and the following ancillary facilities: (1) two 1,000-foot 115 kilovolt ("kV") electric transmission lines to interconnect the generating facility to the New England Power Company ("NEPCo") transmission system; (2) a 200-foot natural gas pipeline to interconnect with the Algonquin pipeline; (3) a 1,000-foot sewer line; (4) a 3,500-foot pipeline to carry wastewater effluent from the Milford Water Treatment Plant ("MWTP") to the proposed facility; and (5) an electrical switchyard (id.; Exhs. EPEC-19, pp. 1-1, 2-2, 2-10, 2-19, HO-RR-79). Other major components of the proposal include (1) a single gas-fired turbine generator; (2) an exhaust heat recovery steam generator ("HRSG"); (3) a steam turbine generator; (4) a wet-cooled, mechanically-induced draft cooling tower; (5) a 100-foot exhaust stack;[5] (6) a 500,000-gallon above-ground water storage tank; (7) a 300,000-gallon demineralized water storage tank; and (8) a 68,000-gallon stormwater retention pond (Exh. EPEC-19, pp. 2-2, 2-17, 6-86).

Potable water and demineralizer make-up water would be purchased from the Milford Water Company ("MWC") (id.,

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4/ Algonquin has filed an application with the Federal Energy Regulatory Commission ("FERC") to construct this new 3.1-mile natural gas pipeline. Pursuant to G.L. c. 164, sec. 69H, and 980 CMR 7.07(9), the Siting Council has intervened in the FERC proceeding regarding this proposed pipeline (FERC Docket CP91-1983-000), has conducted a public hearing to hear environmental concerns relating to this proposal, and plans to submit written comments to FERC on the environmental impacts with suggestions on proposed mitigation measures for this proposal. For further discussion of Algonquin's proposal, see Section II.C.3, below.

5/ EPEC acknowledged that its proposed 100-foot stack is below the Good Engineering Practice ("GEP") stack height of 165 feet for the proposed facility (Tr. 8, p. 56). EPEC asserted that approval of the less-than-GEP stack height by the Massachusetts Department of Environmental Protection ("MDEP") is anticipated, because according to EPEC's analysis, the 100-foot stack would meet all applicable air quality standards (id., p. 51). See Sec. III.E.5, below.

p. 2-15). Air emissions would be controlled through the utilization of steam injection and a selective catalytic reduction ("SCR") system (id., p. 2-18).

The primary site is a 6.8-acre parcel of land in an industrially zoned area approximately one mile southeast of Milford Center (id., p. 2-2). The site is bordered on the east by a Conrail right-of-way ("ROW"), on the south by National Street, on the west by a cemetery, and on the north by vacant land and the Godfrey Brook, a tributary of the Charles River (id.).

In accordance with G.L. c. 164, sec. 69I, EPEC presented an alternative site for the proposed project that is located approximately one mile east of Milford Center and consists of 48 acres of undeveloped, heavily wooded, hilly land (Exh. EPEC-8, p. 2-25).[6] This site is zoned highway industrial, and is bordered on three sides by undeveloped residentially zoned land and on the other side by undeveloped commercially zoned property (id., p. 2-29).

EPEC executed a power purchase agreement ("PPA") with NEPCo on December 19, 1989, for approximately 57 percent of the electrical output from the proposed facility (Exh. EPEC-2, Appendix B).[7] In addition, EPEC has signed a letter of intent to sell power to the Massachusetts Municipal Wholesale Electric Company ("MMWEC"), and currently is negotiating to sell 30 to 40 MW to MMWEC (Exh. HO-RR-3; Tr. 7, pp. 22-23).

EPEC is a subsidiary of Enron Power Corporation ("EPC") (Exh. EPEC-1, p. I-23).[8] Although this is the first project

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6/ See Figure 2 for a map of the alternative site and utility routes.

7/ EPEC has signed a PPA with NEPCo for 83.52 MW (or 57.2 percent) of the proposed operating capacity of 146 MW (see Section II.A.2, below).

8/ EPEC stated that EPC is the wholly owned subsidiary of Enron Corporation ("Enron"), which owns and operates a large natural gas pipeline system nationwide (Exh. EPEC-1, pp. I-23 to I-24).

to be developed by EPEC, EPC now operates 1,300 MW of installed power production facilities in the United States, and would provide "in-house" expertise to EPEC (id., pp. I-24 to I-25, Exh. HO-B-4). On December 19, 1990, EPC sold half of its interest in this project to two affiliates of Jones Capital Corporation ("Jones Capital",) Jones Charles River and Jones Medway (Exh. HO-RR-77; Tr. 7, p. 14). Although Jones Charles River and Jones Medway have no development experience, Jones Capital has developed a cogeneration facility and other major construction projects (id.). EPC and Jones Capital have now established a limited partnership, the Milford Power Limited Partnership ("MPLP"), for the development of the proposed project (id.; Exh. HO-PV-35).

B. Procedural History

On April 6, 1990, EPEC filed with the Siting Council its proposal to construct a bulk generating facility and ancillary facilities (Exhs. EPEC-1, EPEC-2). Representatives of EPEC, the Siting Council and the Massachusetts Environmental Policy Act Unit ("MEPA") of the Executive Office of Environmental Affairs executed a Memorandum of Understanding ("MOU") on June 29, 1990, establishing procedures to coordinate the review of the respective licensing agencies (Exh. EPEC-8, Appendix A).[9] The Siting Council and MEPA held a joint public hearing in Milford on June 26, 1990. EPEC provided notice of public hearing and adjudication as directed by the Hearing Officer.

9/ The Massachusetts Environmental Policy Act requires an applicant for state permits for a major project to notify MEPA of the proposal and file a Draft Environmental Impact Report ("DEIR"), which includes a description of the project, its likely environmental impacts, and proposed mitigation measures. See G.L. c. 30, sec. 62B. State agencies and the public then have 60 days to review and comment on the DEIR (id., sec. 62C). MEPA also may require a Final Environmental Impact Report ("FEIR") to address significant issues raised by the comments on the DEIR. Ultimately, the Secretary of the Executive Office of Environmental Affairs must certify that the FEIR adequately meets the MEPA requirements (id.).

Petitions to intervene were filed by the Charles River Watershed Association ("CRWA"), Concerned Citizens Against Pollution ("CCAP"), Kathleen Tosches ("Tosches"), Joanne Tusino and the Town of Bellingham ("Bellingham"). At a prehearing conference held by the Hearing Officer on July 27, 1990, all five motions to intervene were granted, and a procedural schedule was established for the remainder of the proceeding. Finally, on October 29, 1990, Distrigas of Massachusetts ("DOMAC") submitted a late-filed motion to participate as an interested person in this proceeding. The Hearing Officer granted this motion on February 28, 1991 (Tr. 4, p. 5).

The Siting Council held evidentiary hearings on non-environmental issues on October 30, November 1, and November 6, 1990. At EPEC's request, evidentiary hearings on environmental issues were postponed until after EPEC filed its DEIR with the MEPA Unit on January 31, 1991. Seven days of evidentiary hearings on environmental issues were then held beginning on February 28, 1991, and concluding on March 15, 1991. During the course of the hearings, EPEC presented the testimony of sixteen witnesses: Jude R. Rolfes, vice president of EPC, who testified regarding development, fuel supply and financing issues for the project; Joseph A. Teves, president of DOMAC, who testified concerning the operations of DOMAC and the reliability of the LNG which it supplies; Michael E. Hachey, manager of alternate energy for NEPCo, who testified concerning NEPCo's power purchase from the project; Wayne J. Oliver, principal of Reed Consulting Group, who testified regarding need for the project, the cost of alternative approaches, and a variety of power and gas market issues; Mark W. Gerath, senior hydrologist for ENSR Consulting and Engineering ("ENSR"), who testified on the modeling of the project's impacts on the flow and quality of water in the Charles River; Mary D. Best, Ph.D., senior aquatic ecologist at ENSR, who testified regarding the project's impacts on the aquatic ecology of the Charles River; Steven P. Damiano, a wetlands environmental scientist at ENSR, who testified regarding the project's impacts on the wetlands along the Charles River and the associated utility transmission routes; Howard F. Jenkins, Jr., P.E., project manager for Northern Engineering, who testified concerning the comparison of the project's proposed wet-cooling system with alternative cooling technologies; James W. Kemp, vice president of development engineering for EPC, who testified regarding the overall design of the project; Jon C. Stroble, engineering project manager for EPC, who testified regarding specific design details of the project and ancillary facilities; David B. Smith, vice president of the environmental division of Charles T. Main, Inc., who testified on the environmental benefits associated with displacement of existing generating facilities by the project; Cosmo J. Vaudo, senior toxicologist with ENSR, who testified concerning the health effects of electric and magnetic fields ("EMF") and other aspects of the project; Peter A. Valberg, an environmental consultant with Gradient Corporation and a member of the faculty of the Harvard University School of Public Health, who testified regarding EMF effects; Frederick M. Sellars, senior program manager of ENSR, who testified about the proposed project's impacts on community resources and noise levels associated with the project; Dino B. DeBartolomeis, Chairman of the Milford Board of Selectmen, who testified regarding the Town of Milford's support for the project and the special permit for the project issued by the Town of Milford; and Alfred B. Scaramelli, Ph.D., an independent consultant engaged by the Town of Milford, who testified regarding his assessment of the impacts of the project on the Town of Milford.

CRWA presented the testimony of Andrew Gottlieb, manager of the water management program of MDEP, who testified concerning the water withdrawal permits and the water supply and demand for MWC. Tosches, a Milford resident who lives within one-half mile of the primary site of the proposed project, appeared on her own behalf and testified regarding her assessment of the impact of the proposed project on her neighborhood. CCAP presented two witnesses, Margaret A. Knowlton and Lena McCarthy, residents of Milford, who each presented concerns about environmental and other impacts on their community from the proposed project.

The Hearing Officer entered 175 exhibits into the record, consisting largely of information and record request responses.[10] EPEC entered 19 exhibits into the record. CRWA entered 51 exhibits into the record; CCAP entered 19 exhibits and Tosches entered three exhibits.

EPEC's initial brief ("EPEC Initial Brief") was filed on April 4, 1991. Initial briefs of CRWA ("CRWA Initial Brief"), Bellingham ("Bellingham Initial Brief"), Tosches ("Tosches Initial Brief"), CCAP ("CCAP Brief") and Distrigas ("Distrigas Brief") were filed on April 18, 1991. EPEC's reply brief ("EPEC Reply Brief") was filed on April 25, 1991; and reply briefs were filed by Tosches ("Tosches Reply Brief") on May 1, 1991; Bellingham ("Bellingham Reply Brief") on May 6, 1991 and by CRWA ("CRWA Reply Brief") on May 9, 1991.

On April 12, 1991, CRWA filed a motion to reopen the record to consider the recently issued New England Power Pool Forecast Report of Capacity, Energy, Loads and Transmission ("CELT") 1991-2006 ("1991 CELT Report") (Exh. HO-RR-88). By memorandum dated April 26, 1991, the Hearing Officer ordered EPEC to update relevant exhibits based upon the 1991 CELT Report and invited all parties to submit additional information or supplemental briefs concerning the 1991 CELT Report. EPEC submitted updated exhibits, supplemental information and a letter concerning the 1991 CELT Report on May 10, 1991.[11] The intervenors did not submit additional information or supplemental briefs, although CRWA had previously addressed this issue in its initial and reply briefs.

10/ Some of the responses to information and record requests were provided after the final day of evidentiary hearings.

11/ EPEC did not submit a supplemental brief on this issue. However, EPEC's letter describing the attached exhibits and supplemental information included legal and technical argument. Therefore, this letter will be referred to as the "EPEC Letter Brief" when referenced in this decision.

C. Jurisdiction

EPEC's petition to construct a bulk generating facility and ancillary facilities is filed in accordance with G.L. c. 164, secs. 69H and 69J, which require 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.

As a generating facility with a design capacity of approximately 161 MW, EPEC's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, sec. 69G. That section states, in part, that a facility is:

> (1) any bulk generating unit, including associated buildings and structures, designed for, or capable of operating at a gross capacity of one hundred megawatts or more.

At the same time, EPEC's proposal to construct a transmission line, sewer line, effluent water pipeline, gas pipeline interconnection, and switchyard falls within the third definition of "facility" set forth in G.L. c. 164, sec 69G, which states that a facility is:

> (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 accordance with G.L. c. 164, secs. 69H and 69J, before approving an application to construct facilities, the Siting Council requires non-utility applicants to justify generating 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 (1) consistent with the resource use and development policies of the Commonwealth (see Section II.B, below),[12] and (2) is viable as a source of energy over time (see Section II.C, 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(s) is acceptable in terms of cost, environmental impacts and reliability of supply (see Section III, below). The Siting Council also requires the applicant to show that the primary site for the facility is superior to the alternative site in terms of cost, environmental impacts, and reliability of supply (see Section III, below).

12/ In the past, the Siting Council had required a non-utility applicant to establish that its proposed project was superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need. MASSPOWER, Inc., 20 DOMSC 301, 337-352 (1990) ("MASSPOWER"); Altresco-Pittsfield, Inc., 17 DOMSC 351, 370-378 (1988) ("Altresco-Pittsfield"); Northeast Energy Associates, 16 DOMSC 335, 360-380 (1987) ("NEA"). In MASSPOWER, the Siting Council announced that it would be formulating a new standard of review for evaluating the proposed project (20 DOMSC at 350). In addition, notice of this intention to formulate a new standard of review was communicated to the parties in this proceeding in a memorandum from the Siting Council dated October 4, 1990.

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[13] 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.

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. Eastern Energy Corporation, EFSC 90-100, pp. 15-49 ("EEC"); West Lynn Cogeneration, EFSC 90-102, pp. 7-32 ("West Lynn"); MASSPOWER, 20 DOMSC at 314-323; Altresco-Pittsfield, 17 DOMSC at 360-369; NEA, 16 DOMSC at 344-360; Cambridge Electric Light Company, Commonwealth Electric Company, 15 DOMSC 187, pp. 211-212 (1986) ("1986 CELCO/ComElectric Decision"); Massachusetts Electric

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13/ 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 PPAs, and energy or capacity associated with conservation and load management ("C&LM").

Company/New England Power Company, 13 DOMSC 119, pp. 137-138 (1985) ("1985 MECo/NEPCo Decision"); Massachusetts Electric Company/New England Power Company, 2 DOMSC 1, p. 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, pp. 216-219 (1988); Boston Edison Company, 13 DOMSC 63, pp. 70-73 (1985) ("1985 BECo Decision"); Taunton Municipal Lighting Plant, 8 DOMSC 148, pp. 154-155 (1982); Cambridge Electric Light Company, Commonwealth Electric Company, 6 DOMSC 33, pp. 42-44 (1981); Eastern Edison Company/Montaup Electric Company, 1 DOMSC 312, pp. 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/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, pp. 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 broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources (Hingham Municipal Lighting Plant, 14 DOMSC 7, pp. 14-18 (1985); 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. EEC, EFSC 90-100 at 15-49; West Lynn, EFSC 90-102 at 7-32; MASSPOWER, 20 DOMSC at 311-323; Turners Falls Limited Partnership, 18 DOMSC 141, pp. 151-165 (1988) ("Turners Falls"); Altresco-Pittsfield, 17 DOMSC at 359-365; NEA, 16 DOMSC at 344-360; Massachusetts Electric Company/New England Power Company, 15 DOMSC 241, pp. 273, 281 (1986) ("1986

MECo/NEPCo Decision"); 1985 MECo/NEPCo 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 and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in NEPOOL.

In cases where a non-utility developer seeks to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Council requires the applicant to demonstrate that the utility or utilities needs the facility to address reliability concerns or economic efficiency goals. Where a non-utility developer has proposed a generating facility for a number of power purchasers that include purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, need may be established on a regional basis on either reliability or economic efficiency grounds. EEC, EFSC 90-100 at 15-49; West Lynn, EFSC 90-102 at 10-32; MASSPOWER, 20 DOMSC at 314-323; Altresco-Pittsfield, 17 DOMSC at 361-365; NEA, 16 DOMSC at 344-360. However, the non-utility developer that proposes a generating facility to serve a regional need must also demonstrate to the Siting Council that the proposed facility benefits Massachusetts -- that is, it offers reliability, economic efficiency, or other benefits to the Commonwealth in sufficient magnitude to offset the impacts of the construction and operation of the proposed facility on the Commonwealth's resources. EEC, EFSC 90-100 at 13; West Lynn, EFSC 90-102 at 9; MASSPOWER, 20 DOMSC at 323-336; Turners Falls, 18 DOMSC at 153-164; Altresco-Pittsfield, 17 DOMSC at 361-362, 366-369; NEA, 16 DOMSC at 344-360.

2. Status of EPEC's Power Purchase Agreements

EPEC presented a signed, FERC-approved PPA for the sale of 83.5 MW to NEPCo (Exh. EPEC-2, Appendix B).[14] EPEC also stated that the Board of Directors of MMWEC voted on July 10, 1991 to approve the execution of a PPA with EPEC (Exh. HO-PV-33(2)).[15] Further, EPEC stated that it: (1) is negotiating with Reading Municipal Light Department for the purchase of 10 MW and expects to conclude negotiations within 90 days; (2) has separate pending proposals with UNITIL Power Corporation, Vermont Public Service Corporation, and two other Vermont electric utilities; and (3) has had discussions with Commonwealth Electric Company ("ComElectric") and other electric utilities in the region regarding power purchases (id.; Exh. HO-RR-81; Tr. 7, pp. 22-25). In addition, EPEC stated that it has had discussions with NEPCo regarding the sale of any remaining unsold power to NEPCo on a short-term basis if EPEC does not have all of its capacity committed under long-term contracts at the time of project financing (Tr. 7, pp. 25, 26).

14/ The NEPCo PPA provides that NEPCo is obligated to purchase 58 percent of the capacity of the proposed EPEC project up to a maximum of 83.52 MW (Exh. EPEC-2, Appendix B, p. 14). In much of the record, EPEC refers to the NEPCo PPA as being for 81 MW of capacity, based on the calculation of 58 percent of the proposed project's original estimated net capacity of 140 MW (Exh. EPEC-1, p. II-1). However, based on the proposed project's revised net capacity of 146 MW, the NEPCo PPA obligates NEPCo to purchase 83.52 MW or 57.2 percent (rather than 58 percent) of the proposed project's net capacity (Exh. EPEC-2, Appendix B, p. 14; Tr. 1, p. 146).

15/ EPEC stated that it expected to execute a PPA with MMWEC for 30 to 40 MW of capacity by September 1991 (Exh. HO-PV-33(2)). EPEC explained that, in order to implement the vote of the MMWEC Board of Directors, MMWEC has been authorized to send the proposed contract out to its members for a required vote by the municipal light commissions and the execution by the respective municipalities of repurchase agreements with MMWEC (id.). EPEC provided a copy of the MMWEC Board of Directors vote and a copy of an October 24, 1990 letter from MMWEC stating its intent to negotiate a PPA with MPLP (id.; Exh. HO-RR-3).

EPEC has presented signed and approved PPAs for 83.5 MW of its total output of 146 MW, and has indicated that it intends to sell the remaining portion of its output to Massachusetts' utilities and other regional utilities. Nevertheless, until PPAs for the remaining 62.5 MW are signed and approved, power purchasers for that portion of the project's output are considered to be unknown for the purposes of our review. Therefore, because EPEC proposes to construct a facility for a number of power purchasers that are as yet unknown, the Siting Council evaluates whether New England needs the 146 MW of additional energy resources from the proposed project for reliability or economic efficiency purposes beginning in 1993 and beyond, and whether Massachusetts is likely to receive reliability, economic efficiency, or other benefits from the proposed additional energy resource beginning in 1993 and beyond.[16,17]

16/ EPEC asserted that its analyses support the need for the entire 146 MW output of the proposed project, but EPEC also stated that, in light of its signed and approved PPA for 83.5 MW, it believed that it must demonstrate regional need for only the remaining 62.5 MW (Exhs. EPEC-1, pp. II-5, II-22, HO-N-5). While the Siting Council recognizes that it consistently has found signed and approved PPAs to be determinative on the issue of need for the subscribed power, the Siting Council also consistently has evaluated regional need for the entire output of a generating facility. EEC, EFSC 90-100 at 15; West Lynn, EFSC 90-102 at 10; MASSPOWER, 20 DOMSC at 314; Altresco-Pittsfield, 17 DOMSC at 361. This approach enables the Siting Council to comprehensively evaluate regional need, giving appropriate weight to the signed and approved PPAs, while ensuring that "double-counting" of the committed portion of the project's output does not occur.

17/ EPEC initially asserted that its proposed project would be in operation by July 1992 (Exh. EPEC-1, p. I-43). Later in the proceeding, EPEC testified that it currently planned to be in operation by January 1, 1993 (Tr. 7, p. 45). EPEC's PPA with NEPCO requires the facility to commence operation by January 1, 1994 (Exh. EPEC-2, Appendix B, pp. 9, 10). In addition, EPEC's project development plan estimates an operation date of July 1, 1992, under a "quick start schedule," January 1, 1993, under an "early start schedule," March 1, 1993, under an "expected schedule," and July 1, 1993, under a "late (footnote continued)

3. New England's Need for Additional Energy Resources

a. Introduction

EPEC argued that New England needs additional energy resources for reliability, economic efficiency and environmental purposes (EPEC Initial Brief, pp. II-10 to II-12). Specifically, EPEC argued that additional energy resources would be needed in the region (1) for reliability purposes in the 1995-1998 time period because projected capacity is inadequate to satisfy the region's projected load and reserve requirements,[18] and (2) for economic efficiency purposes because the proposed project would provide power at a lower cost than specific utilities' avoided costs[19] and would produce economic efficiency benefits by displacing higher cost facilities in NEPOOL's dispatch order (id.; EPEC Letter

(footnote continued) start schedule" (Exh. HO-N-8). The Siting Council notes that EPEC's project schedule assumes that approximately 16 months would be required for the construction of the proposed project (Exh. HO-PV-1), and that it appears that EPEC may be able to meet its goal of providing power by early 1993, provided that EPEC can close construction financing in September 1991. Therefore, the Siting Council evaluates regional need beginning in 1993.

18/ EPEC initially argued that additional energy resources were needed in the region for reliability purposes in the 1993-1995 time period (EPEC Initial Brief, pp. II-9 to II-12). Subsequently, however, EPEC revised its argument regarding the time period of need for the proposed project for reliability purposes (EPEC Letter Brief, pp. 2-3). Specifically, EPEC argued that, together with the balance of the record on need, the analyses presented in response to the Hearing Officer's memorandum of April 26, 1991 support the need for the proposed project on reliability grounds within a "reasonable window of need" between 1995 and 1998 (id., p. 3).

19/ The Siting Council examines the avoided costs of the proposed project relative to several Massachusetts' utilities in our review of project viability (see Section II.C.2, below). However, in MASSPOWER, the Siting Council declined to accept the "less than avoided cost" standard as dispositive for the purposes of determining whether New England needs additional energy resources for economic efficiency purposes (20 DOMSC at 323).

Brief).[20] The Siting Council examines EPEC's analysis of New England's need for additional energy resources for reliability and economic efficiency purposes below.

b. New England's Need for Additional Energy Resources for Reliability Purposes

In support of its argument regarding the need for the proposed project on reliability grounds, EPEC originally presented two distinct forecasts of electricity demand and seven supply scenarios for electricity supply for the New England region (Exh. EPEC-1, pp. II-4 to II-17). The first of EPEC's original demand forecasts was based, in large part, on the 1989 CELT Report ("1989 CELT forecast") (id., pp. II-5 to II-8). The second of EPEC's original demand forecasts ("EPEC alternative forecast") was developed by EPEC using an assumed 3.2 percent average annual rate of growth in NEPOOL summer peak load between 1990 and 2004, based on the average annual growth rate in summer peak load experienced by NEPOOL over the 1972-1988 period (id., pp. II-8, II-9). Both the 1989 CELT forecast and the EPEC alternative forecast were paired with seven supply scenarios based on the 1989 CELT Report ("1989

20/ In addition, EPEC argued that additional energy resources would be needed in the region for environmental purposes because the proposed project would provide societal benefits in the form of monetized environmental externality savings by displacing more polluting facilities in NEPOOL's dispatch order (EPEC Initial Brief, pp. II-10 to II-12). The Siting Council notes that our standard of review for need states that the regional need for a proposed project only may be established on reliability or economic efficiency grounds. The Siting Council also notes that monetized environmental externalities are values which can be assigned to the environmental impacts of alternative power supplies for the purposes of comparing alternative resource options, but that such externalities do not represent economic efficiency costs or benefits within the context of our standard of review. The Siting Council examines EPEC's arguments regarding the environmental benefits of the proposed project in our review of Massachusetts benefits (see Section II.A.4.d, below).

supply scenarios") to produce EPEC's 14 original need cases (Exh. EPEC-1, pp. II-11 to II-17).

EPEC provided additional demand forecasts, supply scenarios, and need cases during the course of the proceeding. Specifically, EPEC provided a demand forecast based in large part on the 1990 CELT Report ("1990 CELT forecast") (Exh. EPEC-6). EPEC combined the 1990 CELT forecast with updated versions of its seven supply scenarios based on the 1990 CELT Report ("1990 supply scenarios") to generate a series of additional need cases (id.).[21]

Further, the Hearing Officer, in a memorandum dated April 26, 1991, requested that EPEC and all other parties update the record of the proceeding to reflect the 1991 CELT Report (Exh. HO-RR-88). The Hearing Officer specifically asked EPEC to provide revised versions of several exhibits in the record which addressed regional need, and provided all parties with the opportunity to submit additional arguments and evidence regarding the 1991 CELT report and its impact on the need analyses contained in the record. In response, EPEC provided the requested updated exhibits along with an analysis of the 1991 CELT report prepared by the Reed Consulting Group ("Reed Report") (Exh. HO-RR-106, Attachment 1), and the EPEC Letter Brief.

Finally, EPEC provided the 1989 and the 1990 NEPOOL assessments of resource adequacy (Exh. HO-N-1). EPEC stated that these documents use a probabilistic methodology to establish the level of uncertainty associated with various assumptions employed in the CELT Report (EPEC Initial Brief,

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21/ In response to an information request from the staff, EPEC provided an analysis of the sensitivity of need to the projected rate of regional load growth (Exh. HO-N-25). Specifically, EPEC examined a series of ten constant-growth demand cases ranging from 0.5 percent to 5 percent in increments of 0.5 percent (id.). EPEC combined each of these demand cases with the 1990 supply scenarios to illustrate the sensitivity of projected need to the assumed level of load growth (id.).

p. II-17). EPEC argued that because of the high degree of uncertainty associated with deterministic single point forecasts such as the CELT forecasts, reliance on the NEPOOL resource assessments is a preferable approach for determining regional need (id.).

The Siting Council reviews the various elements of the Company's regional need analyses below.

i. Description

(A) Demand Forecasts

During the course of this proceeding, EPEC presented one demand forecast based on the 1989 CELT Report, three demand forecasts based on the 1990 CELT Report, three additional demand forecasts based on the 1991 CELT Report, and the EPEC alternative demand forecast for NEPOOL adjusted summer peak load. Each of these eight forecasts, which are described below, were modified using EPEC's assumptions regarding required regional reserve margin requirements, and then used as the basis for EPEC's need scenarios. In addition, EPEC presented an analysis of the sensitivity of need to the assumed rate of load growth. EPEC's demand forecasts are summarized in Table 1.

(1) CELT Forecasts

As noted above, EPEC presented a total of seven demand forecasts based on the 1989, 1990 and 1991 CELT reports. As part of its initial petition, EPEC presented the 1989 CELT forecast projections of adjusted summer peak load (Exh. EPEC-1, pp. II-5 to II-8).[22,23] The 1989 CELT forecast projected

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22/ EPEC stated that the adjusted NEPOOL load, as described in the CELT reports, is the weather adjusted peak demand on the system after the inclusion of impacts on load from: (1) interruptible contracts; (2) load management; (3) reduction in losses associated with C&LM programs; and (4) non-utility generation ("NUG") netted from load (Exh. EPEC-1, pp. II-5, II-8; Tr. 2, p. 94).

23/ EPEC stated that the adjusted CELT forecast is (footnote continued)

NEPOOL adjusted summer peak load to increase by an average of 2.15 percent per year through 2004 (id., p. II-6). Shortly after the commencement of this proceeding, NEPOOL issued its 1990 CELT Report (Exhs. HO-N-1, EPEC-6). EPEC, therefore, presented the 1990 CELT Report projections of adjusted summer peak load (id.; Tr. 2, pp. 85, 86). The 1990 CELT forecast projected NEPOOL adjusted summer peak load to increase by an average of 1.99 percent per year through 2005 (Exhs. HO-N-1, HO-RR-106). Further, in response to a request from the Siting Council, EPEC evaluated the impact of (1) a 25 percent increase in the forecast of utility-sponsored C&LM included in the 1990 CELT Report ("1990 high C&LM forecast"), and (2) a 25 percent decrease in the forecast of utility-sponsored C&LM included in the 1990 CELT Report ("1990 low C&LM forecast") (Exh. HO-RR-23).[24]

In addition, at the request of the Siting Council, EPEC presented the 1991 CELT forecast of adjusted summer peak load (Exh. HO-RR-88). The 1991 CELT forecast projected NEPOOL adjusted summer peak demand to increase by an average of 1.3 percent per year through 2006 (id.; Exh. HO-RR-106). In addition, EPEC evaluated the impact of (1) a 25 percent increase in the forecast of utility-sponsored C&LM included in the

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(footnote continued) developed from an unadjusted forecast of peak demand and annual energy use developed by New England Power Planning ("NEPLAN"), the planning arm of NEPOOL, and from C&LM and customer generation estimates provided by NEPOOL's member utilities (Exh. HO-RR-106). EPEC further explained that NEPLAN utilizes a short-term model to forecast demand over a 24-month period and a long-term model to forecast demand over the remainder of NEPOOL's 15-year forecast horizon (id.). EPEC noted that NEPLAN's short-term forecast is produced by an econometric model which relies on three exogenous inputs -- real personal income, population, and real electricity prices -- whereas the long-term forecast is produced by an end-use model which incorporates a large number of assumptions regarding economic and demographic growth, price elasticities, and other factors (id.).

24/ As utility-sponsored C&LM is netted against load to develop the CELT peak adjusted forecast, these assumptions lead to two new demand forecasts.

1991 CELT Report ("1991 high C&LM forecast"), and (2) a 25 percent decrease in the forecast of utility-sponsored C&LM included in the 1991 CELT Report ("1991 low C&LM forecast") (id.).

EPEC's witness, Mr. Oliver, stated that the 1990 CELT forecast of adjusted summer peak demand was somewhat lower than the 1989 CELT forecast because of (1) a lower unadjusted peak demand forecast in the 1990 CELT Report for the years 1989-1993, and (2) higher projected reductions in peak demand due to C&LM programs in the 1990 CELT Report for the 1994-2004 period (Exh. EPEC-1, p. 6). Mr. Oliver concluded that the differences between the 1989 and 1990 CELT forecasts are significant only over the 1989-1993 period (id., pp. 6, 7).

EPEC noted, however, that the 1991 CELT forecast projects significantly lower growth in regional demand than the 1990 CELT forecast (Exh. HO-RR-106). EPEC further noted that the 1991 CELT forecast projects a significantly different pattern of growth than the 1990 CELT forecast, particularly in the 1991-1997 time frame (id.). Specifically, EPEC noted that the 1991 CELT forecast projects that peak demand levels are expected to drop between 1990 and 1992 and are not projected to return to 1990 levels until 1997 (id.).

As noted above, EPEC also presented the Reed Report, a critique of the 1991 CELT forecast. The Reed Report states that the 1991 CELT forecast is lower than the 1990 CELT forecast due, in large part, to lower estimates of regional economic growth, higher projected real electricity prices, and higher estimates of demand reductions from C&LM and customer generation (id., Attachment 1, pp. 3-12). The Reed Report further states that NEPOOL's projections of slow economic growth and higher electricity prices are each driven in large part by its forecast of high fuel prices (id., pp. 7, 8).

The Reed Report criticizes many of the assumptions upon which the 1991 CELT forecast is based. Specifically, the Reed Report notes that the economic forecast used to develop the 1991 CELT forecast projects a decline in real personal income in

New England through 1991 with only a modest recovery over the remainder of the forecast period (id., p. 6). The Reed Report further notes that the projection of economic decline on which the 1991 CELT forecast is based lasts significantly longer than the declines experienced in the region during both the 1973-1975 and 1981-1982 recessions, and that the rate of recovery predicted in the economic projection used in the 1991 CELT Report is much slower than the actual regional recoveries which followed these historic recessionary periods (id.). In addition, the Reed Report asserts that the 1991 CELT Report does not recognize the historic fact that electricity sales have risen substantially as the region emerges from recessionary periods (id.).

The Reed Report also notes that the 1991 CELT forecast is based on a fuel price forecast issued immediately following the 1990 invasion of Kuwait by Iraq (id., p. 7). The Reed Report asserts that the use of this fuel price forecast results in a lower forecast of economic growth and a sharp rise in projected electricity prices, both of which act to drive down projected electricity sales (id.). The Reed Report also notes that the fuel price forecast used in the 1991 CELT forecast projects the price of residual oil to be over $22 per barrel in 1991, while the actual price as of the date of issuance of the Reed Report (April 1991) was approximately $15 per barrel (id.).[25]

25/ The Reed Report further asserts that NEPOOL has consistently underforecasted the region's peak demand for electricity (Exh. HO-RR-106, Attachment 1, p. 8). In support of this assertion, EPEC provided a chart which indicates that NEPOOL underforecasted summer adjusted peak in most years between 1982 and 1989 (Exh. EPEC-1, pp. II-8, II-9). In response to a record request by the Siting Council, EPEC provided additional information on NEPOOL's forecasting record, which indicated that NEPOOL generally overestimated summer peak between 1975 and 1979, but generally underestimated summer peak between 1980 and 1988 (Exh. HO-RR-20).

Based upon these criticisms of the 1991 CELT forecast, EPEC argued that, although it may generally be presumed that an updated demand forecast is more accurate than an earlier forecast, the 1991 CELT forecast is not the most accurate assessment of need for reliability purposes in the record (EPEC Letter Brief, pp. 2, 3). EPEC noted that the trend over the three most recent CELT forecasts has been towards a widening gap from NEPOOL's long-term growth rate, and stated that the 1991 CELT forecast may "overcorrect for the historical long-term rates by relying too heavily on short-term economic and fuel price data" which is overly pessimistic (id., p. 2). EPEC further stated that the credibility of the 1991 CELT forecast is placed in doubt by the fact that its adjusted average annual growth rate for summer peak load is 1.3 percent, whereas the 1990 resource assessment, published less than one year earlier, concluded that a growth rate of 1.26 percent or lower had a probability of less than 10 percent of occurring (id.; Exh. HO-N-1).

In sum, EPEC argued that the 1989 and 1990 CELT forecasts and the 1990 high and low C&LM forecasts are appropriate to evaluate regional need, but that the 1991 CELT forecast, the 1991 low C&LM forecast, and the 1991 high C&LM forecast lacked credibility (EPEC Letter Brief, pp. 2, 3).

(2) Alternative Demand Forecast

In addition to the CELT forecasts discussed above, EPEC presented the EPEC alternative forecast (Exh. EPEC-1, pp. II-8, II-9). EPEC stated that, given the divergence between New England's recent actual peak load growth rates and the growth rates currently being forecast by NEPOOL, it would be appropriate to examine a demand scenario which reflects the actual historical rate of demand growth in the region (id., p. II-8). EPEC stated that it chose to analyze historical growth over the 1972-1988 period because this period is of sufficient duration to capture many market changes, including periods of economic recession and expansion, periods of rising and falling oil prices, and periods with wide variation in inflation and interest rates (Exh. HO-N-3). The EPEC alternative forecast projects that NEPOOL's adjusted summer peak demand will increase by an average of 3.2 percent per year through 2004 based on the average annual growth rate in summer peak load experienced by NEPOOL over the 1972-1988 period (id., pp. II-8, II-9).

EPEC asserted that the EPEC alternative forecast is a reasonable mid-term forecast which should be considered for several reasons (id., p. II-9). First, EPEC argued that although slower economic growth in New England may temporarily depress peak demand, the region's long-term experience indicates that short-term fluctuations in demand can be misleading (id.). EPEC noted that despite two recessions and rapidly rising electricity prices, regional demand growth averaged 3.2 percent annually over the 1972-1988 period (id.). Second, EPEC asserted that slower growth in NEPOOL peak demand since 1988 has been influenced by cooler than normal weather and NEPOOL's use of emergency actions to curtail load during peak periods (id., p. II-10). Third, EPEC asserted that there is no evidence to indicate that electricity prices will rise significantly in the near term, and that lower than anticipated electricity prices will lead to higher demand (id.). Fourth, as noted in the previous section, EPEC stated that NEPOOL has consistently underforecasted peak demand in the last decade (id., pp. II-8, II-9).

Finally, in support of the use of a long-term growth trend such as the EPEC alternative forecast to determine the need for a project's capacity in the short-term,[26] Mr. Oliver

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26/ In examining the need for a proposed project for reliability purposes, the Siting Council looks at the first year of continuous need for the project's capacity. See EEC, EFSC 90-100 at 49; West Lynn, EFSC 90-102 at 32; MASSPOWER, 20 DOMSC at 18-19. Projected short-term to medium-term demand growth rates are most relevant to determine the first year of continuous need for a project's capacity.

stated that an annual growth rate of 3.2 percent was conceivable in the short run because the demand for electricity historically has increased substantially as the region emerges from a recession (Tr. 2, p. 101). Mr. Oliver further stated that, given uncertainty in the outlook for electricity demand in the region, it is appropriate to examine a wide range of demand forecasts in determining the need for a project (id., p. 102). Mr. Oliver also stated that the 1990 CELT forecast projects peak growth of just 0.22 percent between 1989 and 1991, and thus should be considered a low forecast in the short term (id.).

(3) Reserve Margin

EPEC stated that NEPOOL participants are required to maintain a capacity reserve margin above the capacity required to meet their forecasted peak load in order to assure supply adequacy in the region (Exh. EPEC-1, p. II-10). Therefore, in order to account for the overall capacity requirements of the NEPOOL system in its regional need analysis, EPEC added a reserve margin to its eight demand forecasts prior to using them to develop the need cases (id.).

EPEC stated that the CELT Reports do not provide a forecast for reserve margin, but that other NEPOOL documents do provide such a forecast (id.). EPEC indicated that it used the reserve margin forecast contained in NEPOOL's Electricity Price Forecast for New England, 1989-2004, (April 1989), in its regional need analysis (id., pp. II-7, II-10; Tr. 2, p. 98). Specifically, EPEC applied a reserve margin of 25 percent for the period 1990-1992, 23 percent for the period 1993-1996, and 20 percent thereafter (Exh. EPEC-1, pp. II-7, II-10). EPEC stated that it believed that this forecast of regional reserve requirements was conservative, based on conversations with regional utilities and information contained in the NEPOOL resource assessments, which indicated that required NEPOOL reserves would likely be higher than those employed by EPEC in its analyses because of the increased regional reserve requirements associated with the Seabrook I Nuclear Generating Station ("Seabrook") generating unit and Hydro-Quebec Phase II import project (id., pp. II-10, II-11; Tr. 2, pp. 96-99).

(4) Load Growth Sensitivity Analyses

In response to a request from the Siting Council to perform a sensitivity analysis to demonstrate the need, if any, for the capacity of the proposed project under a broad range of potential regional load growth scenarios, EPEC provided a series of ten constant-growth demand cases ranging from 0.5 percent to 5 percent in increments of 0.5 percent (Exh. HO-N-25). EPEC combined each of these demand cases with the 1990 supply scenarios to provide further evidence regarding the first year of continuous need for the capacity of the proposed project (id.).

(B) Supply Forecasts

EPEC stated that there are significant uncertainties associated with the availability of future capacity additions (Exh. EPEC-1, pp. II-11, II-12). In order to address such uncertainties, EPEC presented the seven 1989 supply scenarios as part of its initial petition. These seven distinct supply scenarios were used with the 1989 CELT forecast and EPEC alternate forecast to develop EPEC's initial 14 need cases (id., pp. II-15 to II-17). During the course of the proceeding, EPEC revised these seven supply scenarios slightly to incorporate updated supply projections contained in the 1990 and 1991 CELT reports (Exhs. EPEC-6, pp. 5, 9, HO-RR-106). The 1990 supply scenarios were combined with the 1990 CELT forecast, 1990 high C&LM forecast and the 1990 low C&LM forecast, and the 1991 supply scenarios were combined with the 1991 CELT forecast, 1991 high C&LM forecast, and 1991 low C&LM forecast, to generate a series of additional need cases (Exh. HO-RR-106).

EPEC stated that the CELT Reports provided a comprehensive database of both existing generation and future capacity additions (Exh. EPEC-1, p. II-11).[27] EPEC noted that the CELT Reports assume the availability of the following resources: (1) all existing generation; (2) all committed but as yet unrealized utility and non-utility generation;[28] (3) all planned unit life extensions and retirements within NEPOOL; and (4) all firm purchases and sales with entities outside of NEPOOL (id., pp. II-11, II-12).

EPEC stated that the 1989, 1990 and 1991 supply scenarios were all based on the same seven basic supply contingency cases (Exhs. EPEC-6, pp. 5, 9, HO-RR-106). EPEC stated that in developing these supply contingencies, it attempted to illustrate a range of realistic possibilities while capturing the major uncertainties that exist in NEPOOL's forecast of supplies (Exhs. EPEC-1, p. II-15, HO-N-4). These supply cases differed from one another in one or more of the following respects: (1) the fraction of committed NUG capacity which will come on-line; (2) the fraction of uncommitted NUG capacity which

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27/ EPEC stated that, with the exception of the Ocean State Power II facility (see footnote 30, below), it included all planned utility generation additions over the next 15 years listed in the 1989 CELT Report, including Seabrook, the Hydro-Quebec Phase II purchase, other hydropower units, and Ocean State Power I, in each of its supply scenarios, although it asserted that there is some uncertainty regarding whether all of these planned units will come on line as scheduled (Exh. EPEC-1, p. II-12). EPEC further stated that in all scenarios it: (1) included the Pilgrim plant; (2) classified the Bellingham plant as committed; and (3) assumed that the Hydro-Quebec Phase II purchase agreement would be extended beyond its current expiration date in 2000 (id., pp. II-11 to II-14). The Bellingham plant, a 300 MW gas-fired facility, was approved by the Siting Council in NEA, 16 DOMSC at 338.

28/ EPEC stated that NEPOOL includes all existing resources and all planned resources which are under construction or have the majority of their regulatory approvals as committed resources in the CELT Reports (Tr. 2, p. 109).

will come on-line;[29] (3) the existence of a one-year delay for all non-committed NUGs; (4) whether the Ocean State Power II facility will come on-line;[30] and (5) capacity attrition for existing generation[31,32] (Exh. EPEC-1, pp. II-15 to II-17).

29/ In its supply contingencies, the range of availability of committed NUG capacity varied from 50 to 100 percent and the range of availability of uncommitted NUG capacity varied from 0 to 50 percent (Exh. EPEC-1, p. II-17). EPEC noted that the CELT forecasts assume that 100 percent of committed NUG capacity will come on-line, but that experience has demonstrated that such facilities will have an attrition rate of approximately 50 percent (id., pp. II-13, II-14). EPEC further stated that although some of the non-committed NUGs included in the 1989 CELT Report are likely to go on-line, it is highly unlikely that all projects listed in the 1989 CELT Report would succeed (id., p. II-14).

30/ EPEC stated that it chose to examine supply scenarios both with and without the Ocean State Power II facility because it is the only facility classified by NEPOOL as committed generation which is expected to come on-line in approximately the same time frame as EPEC's proposed project (Exh. EPEC-1, p. II-12; Tr. 2, pp. 99, 100).

31/ EPEC stated that NEPOOL has assigned a 40 percent probability to the event that up to 500 MW of existing NEPOOL capacity could become unavailable due to such factors as component failures which are too expensive to repair or regulatory shutdown due to safety or environmental issues (Exh. EPEC-1, p. II-14).

32/ Specifically, EPEC's seven basic supply contingency cases assumed the following: scenario 1 -- 50 percent of committed NUGs and 0 percent of non-committed NUGs on-line, Ocean State Power II on-line, no attrition of existing capacity; scenario 2 -- 50 percent of committed NUGs and 50 percent of non-committed NUGs on-line, Ocean State Power II on-line, no attrition of existing capacity; scenario 3 -- 50 percent of committed NUGs and 50 percent of non-committed NUGs on-line, Ocean State Power II on-line, attrition of existing capacity; scenario 4 -- 50 percent of committed NUGs and 50 percent of non-committed NUGs on-line, Ocean State Power II not on-line, attrition of existing capacity; scenario 5 -- 75 percent of committed NUGs and 50 percent of non-committed NUGs on-line, Ocean State Power II on-line, attrition of existing capacity, scenario 6 -- 100 percent of committed NUGs and 0 percent of non-committed NUGs on-line, Ocean State Power II not on-line, no attrition of existing capacity; and scenario 7 -- 50 percent of committed NUGs on line, 50 percent of non-committed NUGs on-line but with a one year delay, Ocean State Power II on-line; attrition of existing capacity (Exhs. EPEC-1, pp. II-16 to II-21, HO-N-28).

EPEC stated that it originally believed that scenario 7 was the most likely supply scenario, but that with recent changes in the power supply market resulting from the short-term slowdown in the regional economy and the status of uncommitted NUGs, EPEC now believes that scenario 5 now has the highest probability of occurrence in the short-term to mid-term and that scenarios 3 and 7 have a fairly high probability of occurrence in the short run (Exh. HO-N-29). Of the seven supply scenarios, scenario 2 assumes the highest level of available supplies and scenario 7 assumes the lowest level of available supplies (Exh. EPEC-1, pp. II-19, II-20). Scenarios 2 and 7 differ by 558 MW in 1993, 642 MW in 1994, and 725 MW in 1995 (id.).

(C) Need Cases

In order to evaluate the need for additional energy resources in New England, EPEC developed a series of need cases based on a comparison of its demand forecasts and its supply cases. Originally, EPEC presented 14 need scenarios which were developed by relating its two original demand forecasts (the 1989 CELT forecast and the EPEC alternative forecast) to the seven 1989 supply scenarios. Of these 14 need cases, seven (all of those based on the EPEC alternative forecast) identified 1992 as the first year of continuous need for at least 146 MW and all cases showed a need for at least 146 MW by 1994 (id., EPEC-1, pp. II-19 to II-21).

As described above, EPEC updated the record shortly after the beginning of the proceeding to include the 1990 CELT forecast. EPEC then combined the 1990 CELT forecast with its seven updated 1990 supply scenarios to generate seven additional need cases (Exhs. EPEC-6, HO-N-25, HO-RR-24). Further, EPEC developed another 14 new need cases based on the 1990 high C&LM forecast, the 1990 low C&LM forecast, and the 1990 supply scenarios (Exh. HO-RR-23).

In sum, the Company evaluated a total of 21 need cases based on the 1990 CELT forecast, the 1990 high C&LM forecast, the 1990 low C&LM forecasts, and the 1990 supply scenarios.

Of these, one case (5 percent) shows a need for at least 146 MW by 1993, 16 cases (76 percent) show a need for at least 146 MW of additional energy resources by 1994, and all cases show a need for at least 146 MW of additional energy resources by 1995.

Finally, EPEC combined the 1991 CELT forecast with its seven 1991 supply scenarios to generate seven additional need cases (Exh. HO-RR-106). In addition, EPEC developed another 14 need cases based on the 1991 high C&LM forecast, the 1991 low C&LM forecast, and the 1991 supply scenarios (id.).

EPEC evaluated a total of 21 need cases based on the 1991 CELT forecast, the 1991 high and low C&LM forecasts, and the 1991 supply scenarios. All of these 21 cases show a need for at least 146 MW of additional energy resources beginning between 1999 and 2001 (id.).

In summary, EPEC combined eight demand forecasts with three sets of seven supply scenarios to generate a total of 56 distinct need cases. Of these 56 need cases, eight cases (14 percent) show a need for at least 146 MW by 1993, 30 cases (54 percent) show a need for at least 146 MW by 1994, and 35 cases (63 percent) show a need for at least 146 MW by 1995. Tables 2 and 3 set forth these results.

In addition, as noted above, EPEC performed an analysis of the sensitivity of need to variations in projected load growth (Exh. HO-N-25). In this load growth sensitivity analysis, EPEC combined each of ten constant growth demand cases with the seven 1990 supply scenarios to generate 70 additional need cases (id.).

EPEC's load growth sensitivity analysis indicates that the projected first year of continuous need for at least 146 MW is highly sensitive to the load growth rate assumed. For example, none of the seven need scenarios based on a constant growth rate of 0.5 percent annually show a need for 146 MW of additional resources until after 2000 (id.). In contrast, all 35 of the need scenarios based on a constant growth rate of three percent or higher show a need for at least 146 MW by 1993, and 48 of the 49 scenarios (98 percent) based on a constant growth rate of two percent or higher show a need for at least 146 MW by 1994 (id.). Overall, 55 of the 70 scenarios included in EPEC's load growth sensitivity analysis (79 percent) show a need for at least 146 MW of capacity by 1995 (id.). Table 4 sets forth these results.

EPEC argued that, rather than relying on a single deterministic forecast of regional demand, the Siting Council should weigh its analyses of need based on the 1989, 1990 and 1991 CELT forecasts and the EPEC alternative forecast to determine a window of need from this range of forecasts (EPEC Letter Brief, p. 3). EPEC further argued that its analyses of need based on the three CELT forecasts, the EPEC alternative forecast, and the three sets of seven alternative supply scenarios demonstrate that there is a need for at least 146 MW of additional capacity in the region within the 1995-1998 time period for reliability purposes (id., pp. 2, 3; EPEC Initial Brief, pp. II-9, II-10).

(D) NEPOOL Resource Assessments

To further support the validity of the results of EPEC's need analyses, EPEC provided the 1989 and 1990 NEPOOL resource assessments (Exh. HO-N-1). EPEC noted that the NEPOOL resource assessments emphasize the uncertainty surrounding both the 1989 and 1990 CELT forecasts and the adequacy of the projected available resources as identified in the 1989 and 1990 CELT reports (Exh. EPEC-1, p. II-23). EPEC stated that, in contrast to the CELT reports, which provide a single point estimate of need for a particular year, the NEPOOL resource assessments evaluate uncertainty in a probabilistic fashion (id.; Exh. HO-N-26). EPEC stated that, in the resource assessments, NEPOOL attempts to assess the likelihood that resources will be adequate to meet requirements by assigning probabilities to a range of potential values of several important variables which influence resource adequacy (id.).[33] EPEC asserted that the use of this probabilistic approach "allows NEPOOL to systematically evaluate the impacts of a range of possible outcomes from several key variables on the adequacy of resources to meet the NEPOOL reliability criterion" (Exh. HO-N-26).

Specifically, the Company stated that the 1989 NEPOOL resource assessment evaluated the impacts of the following variables on the resource adequacy of the basic 1989 CELT Report results ("1989 CELT case"): (1) load growth; (2) C&LM impacts on peak load; (3) reserve requirements; (4) timing and amounts of committed non-utility generation; (5) timing and amounts of planned, uncommitted non-utility generation; (6) attrition of existing resources; (7) in-service dates of Ocean State Power I and II; and (8) in-service date of Hydro-Quebec II (Exhs. HO-N-1, EPEC-1, p. II-23). EPEC stated that the 1990 resource assessment evaluated the impacts of the following variables on the resource adequacy of the basic 1990 CELT Report results ("1990 CELT case"): (1) all of the variables evaluated for the 1989 CELT case with the exception of the in-service dates of Ocean State Power I and II and the in-service date of Hydro-Quebec II; and (2) 1991 Hydro-Quebec transfer capability (id.).[34]

33/ EPEC explained that the NEPOOL resource assessments initially identify individual probability distributions for each of the underlying variables examined (Exh. HO-N-1; EPEC Initial Brief, p. II-17). The probability associated with a specific capacity position reflects the individual probabilities associated with the values of the underlying variables which form the basis of the specific capacity position (id.). NEPOOL then develops probability bands around each capacity position to reflect the uncertainty associated with each position (id.).

34/ In addition to the evaluation of the 1990 CELT case, the 1990 NEPOOL resource assessment evaluated a second resource scenario identified as the "CELT case with contingency resources" (Exh. HO-N-1). The CELT case with contingency resources assessed NEPOOL's resource adequacy for all of the variables included in the 1990 CELT case plus the uncertainties associated with (1) uncommitted utility units, which are units (footnote continued)

EPEC stated that the 1989 NEPOOL resource assessment concluded that there was only a 31 percent chance that NEPOOL would have adequate resources in 1995 to meet its reliability criterion for the 1989 CELT case, while the 1990 NEPOOL resource assessment concluded that there was a 42 percent probability that NEPOOL would have sufficient resources in 1995 based on the 1990 CELT case (Exhs. EPEC-1, p. II-25, HO-N-1). The 1989 NEPOOL resource assessment of the 1989 CELT case identified a need for approximately 250 MW of additional capacity in 1993, 760 MW of additional capacity in 1994, and 1,400 MW of additional capacity in 1995 to achieve a 50 percent confidence level (Exh. EPEC-1, p. II-24). In addition, the 1989 CELT case identified a need for approximately 1,600 MW of additional capacity in 1993, 2,200 MW of additional capacity in 1994, and 2,800 MW in 1995 to achieve an 70 percent confidence level (id.). In contrast, the 1990 NEPOOL resource assessment of the 1990 CELT case identified a capacity surplus of 700 MW in 1993, a capacity surplus of 200 MW in 1994, and a need for 500 MW of additional capacity in 1995 to achieve a 50 percent confidence level (Exhs. EPEC-6, p. 8, HO-N-1). In addition, the 1990 CELT case identified a need for approximately 500 MW of additional capacity in 1993, 1,100 MW of additional capacity in 1994, and 1,800 MW of additional capacity in 1995 to achieve a 70 percent confidence level (id.).

EPEC argued that single-point, deterministic forecasts of demand such as the CELT forecasts are inherently uncertain and unstable, and therefore that the probabilistic approach employed

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(footnote continued) planned by utilities but which have not yet received all regulatory approvals, and (2) contingency capacity and contingency DSM programs, which are uncommitted resources with planned on-line dates within the 1991-1995 period (id.). This evaluation indicates that these resources are planned to be implemented if load growth increases or if planned projects do not progress on schedule (id.). This evaluation further indicates that most of these contingency resources have a four-year to five-year lead time and only will be available in 1995 if decisions to proceed are made within 12 to 18 months of the issue date of the 1990 NEPOOL resource assessment (id.).

by NEPOOL in its resource assessments is a preferable method for evaluating resource adequacy (Exhs. EPEC-1, pp. II-4, II-25, HO-N-26, HO-RR-106, Attachment 1, pp. 8, 11, 12). EPEC stated that the probabilistic approach used in the resource assessments allows NEPOOL to systematically analyze a broad spectrum of possible outcomes based on a range of input values in order to assess the degree of uncertainty associated with resource adequacy (Exh. HO-N-26). EPEC asserted that "this [approach] enhances planning capability by establishing a reasonable range of outcomes for planning purposes, as opposed to a single point estimate for need, which has a high probability of being wrong" (id.).

In addition, EPEC stated that the approach incorporated in the 1989 and 1990 resource assessments requires an explicit balancing of cost and reliability (Exh. EPEC-1, p. II-25). EPEC further stated that it is unable to perform an analysis of the appropriate reliability level at which the cost of incremental resources are balanced with the cost of energy shortfalls, but that Boston Edison Company ("BECo") has performed such an analysis for its system and found that a 70 percent confidence level provides a reasonable balance between these two costs (id.). EPEC further stated that the Siting Council has accepted BECo's analysis (id.). See Boston Edison Company, 18 DOMSC 201, 207 (1989) ("1989 BECo Decision"). EPEC stated that it believes that a 70 percent confidence level represents a reasonable balance of cost and adequacy (Exh. EPEC-1, p. II-25).

In sum, EPEC argued that the 1989 and 1990 resource assessments clearly demonstrate that there is a need for at least 146 MW of capacity in the region in the 1992-1994 timeframe on reliability grounds (id., pp. II-25, II-26; Exh. EPEC-6, pp. 8, 9).

ii. Arguments of the Parties

CRWA argued that EPEC has failed to establish that the additional energy resources from its proposed project are needed (CRWA Initial Brief, p. 5). Specifically, CRWA argued that

(1) EPEC has not demonstrated a need for the entire output of the project because a significant portion of the facility's output has not been sold, and (2) the need for the proposed project is based on projections which are outdated and no longer applicable (id.).

CRWA further argued that the 1991 CELT forecast exhibited a marked decline in the projected demand for power in the region (CRWA Initial Brief, p. 5). CRWA asserted that the 1991 CELT forecast shows a lack of need for new power plant construction in New England in the near future (id., p. 6). With regard to EPEC's PPA with NEPCo, CRWA asserted that "given the continued slump in energy requirements among commercial consumers, NEPCo has contracted to purchase energy that it does not need. The contract for the sale of the energy produced does not, therefore, constitute need in the sense of a regional requirement, but need only in terms of a contractual obligation" (CRWA Reply Brief, p. 4).

In response to the arguments of CRWA, EPEC asserted that the proposed project would satisfy the Siting Council's need standard even if the 1991 CELT Report showed no load growth at all because the existing NEPCo PPA is for a majority of the proposed project's output and the risk that the remainder of the project's output would be unsold is small, (EPEC Reply Brief, p. 5). In addition, EPEC asserted that the 1991 CELT Report shows adjusted average annual growth rates of 1.3 percent for summer peak and 1.35 percent for winter peak, and that EPEC's growth rate sensitivity analyses demonstrate the need for the proposed project for reliability purposes within three to four years of the project's expected startup of operations under such growth rates (EPEC Reply Brief, p. 5). EPEC also reiterated that the proposed project is needed for economic efficiency purposes (id.).

Ms. Tosches argued that the proposed project is not needed because: (1) new C&LM programs being implemented by electric companies will greatly reduce the region's need for new power plants; (2) there are a number of alternatives, such as solar power, which can produce energy without damaging the environment; and (3) EPEC has not succeeded in selling the full output of its proposed plant (Tosches Initial Brief, pp. IV-17 to IV-18; Exh. T-1, p. 5). In response to these arguments, EPEC asserted that much of Ms. Tosches' analysis of C&LM and alternative sources of energy is not supported by the record (EPEC Reply Brief, p. 25).

iii. Analysis

In its analysis of the need for the proposed project for reliability purposes, EPEC has, during the course of this proceeding, developed and presented a total of 56 distinct need cases based on eight separate demand forecasts and three sets of seven supply scenarios. EPEC also has prepared a sensitivity analysis which illustrates the sensitivity of need to various levels of potential future load growth. In addition, EPEC has presented analyses of need based on the 1989 and 1990 NEPOOL resource assessments. EPEC's analysis of regional need is quite comprehensive in comparison with the majority of analyses of regional need presented to the Siting Council in the past by non-utility developers. See West Lynn, EFSC 90-102 at 10-32; MASSPOWER, 20 DOMSC at 314-322; Altresco-Pittsfield, 17 DOMSC at 362-365; NEA, 16 DOMSC at 351-354.

EPEC presented a set of eight demand forecasts, one of which is based on the 1989 CELT Report, three of which are based on the 1990 CELT Report, three of which are based on the 1991 CELT Report, one of which is based on an extrapolation of NEPOOL's historical long-term growth rate (the EPEC alternative forecast). EPEC did not nominate any of these demand forecasts as a base case, although it did argue that the 1991 CELT forecast is overly pessimistic. Rather, EPEC argued that the Siting Council should weigh each of the CELT forecasts and the EPEC alternative forecast together to determine a window of need for the capacity of the proposed facility.

In past decisions, the Siting Council has accepted the use of NEPOOL CELT forecasts for the purposes of evaluating regional need. EEC, EFSC 90-100 at 42-44; MASSPOWER, 20 DOMSC at 321; Altresco-Pittsfield, 17 DOMSC at 364; NEA, 16 DOMSC at 354. The Siting Council agrees with EPEC that the NEPOOL CELT forecasts generally can provide an appropriate starting point for resource planning in New England. However, in EEC, the Siting Council found that it is not appropriate to rely on multiple versions of the same forecast to develop a range of possible future resource needs (EFSC 90-100 at 42). The Siting Council stated in that decision that the value of the use of multiple forecasts to develop a range of plausible future resource needs lies in the differences in the underlying methodologies and assumptions used to develop such forecasts. Id. The Siting Council further stated that the use of multiple forecasts based on essentially the same assumptions and methodologies adds little in the way of forecast reliability and, in fact, may tend to increase the influence of any inappropriate assumptions or any errors contained within a methodology. Id.

The Siting Council found in EEC that the 1989 and 1990 CELT forecasts rely on similar methodologies and assumptions and that, because the 1990 CELT forecast relies on more recent data than the 1989 CELT forecast, the 1990 CELT forecast and the need cases developed from it were more appropriate than the 1989 CELT forecast and associated need cases for purposes of evaluating regional need in that proceeding (EFSC 90-100 at 42). Here, the record supports a similar finding.

Accordingly, based on the foregoing, the Siting Council finds that the 1989 CELT forecast and the need cases developed from it should not be used for the purposes of evaluating regional need in this proceeding.

The Siting Council shares EPEC's concerns regarding the appropriateness of using the 1991 CELT forecast to evaluate regional need. While we have stated that more recent data justifies use of the 1990 CELT forecast rather than the 1989

CELT forecast, it does not follow that the 1991 CELT forecast is an appropriate replacement for the 1990 CELT forecast for purposes of evaluating regional need in this proceeding. While the 1989 and 1990 CELT forecasts employ similar assumptions and methodologies, the 1991 CELT forecast is based on a substantially different set of assumptions.

In two recent decisions, the Siting Council has expressed serious reservations regarding the credibility of the 1991 CELT forecast. EEC, EFSC 90-100 at 43, 44; West Lynn, EFSC 90-102, at 26, 27. The Siting Council initially expressed its concerns regarding the 1991 CELT forecast in West Lynn, where we noted that the 1991 CELT forecast departs dramatically from long-term historic trends and we expressed our concerns as to the weight that should be accorded that forecast in a review of regional need (EFSC 90-102 at 26-27). In EEC, the Siting Council stated that our concerns with the 1991 CELT Report arise from (1) its failure to reflect discernable long-term historic trends, and (2) its marked inconsistency with other long-term forecasts of similar vintage (EFSC 90-100 at 43). In that proceeding, the Siting Council found that the 1991 CELT forecast and the need cases developed from it should not be used for the purpose of evaluating regional need. Id. at 44.

Here, EPEC has presented a critique of the 1991 CELT forecast which indicates that the 1991 CELT forecast is premised on several questionable assumptions, and consequently, appears to underestimate potential regional load growth. Based upon the evidence provided in this critique, the Siting Council is persuaded once again that the use of unduly pessimistic economic assumptions and higher electricity prices, each driven by a fuel price forecast which has proven to be significantly overstated in the short-term, has compromised the validity of the 1991 CELT forecast for the purposes of evaluating regional need.

Accordingly, based on the foregoing, the Siting Council finds that the 1991 CELT forecast and the need cases developed from it should not be used for the purpose of evaluating regional need in this proceeding.

With regard to the EPEC alternative forecast, the Siting Council notes that it is based on the same assumptions and methodology as an alternative forecast presented in EEC (EFSC 90-100 at 24-25). In EEC, the Siting Council found that the use of a 3.2 percent constant growth rate forecast as an alternative forecast was appropriate for the purposes of evaluating regional need because (1) it was based on a completely different methodology than the CELT forecasts, and (2) EEC supported the reasonableness of this growth rate by comparing it to the growth rate of the U.S. Gross National Product (EFSC 90-100 at 44-45). The Siting Council further stated, however, that the use of an alternative forecast based on such a simplistic methodology is appropriate only in cases where that alternative forecast is being compared to a forecast developed through a more sophisticated methodology. Id. at 45.

Here, EPEC has presented several reasonable arguments supporting the use of the EPEC alternative forecast as a reasonable high case alternative to the CELT forecasts. In particular, EPEC's arguments that NEPOOL has consistently underestimated regional demand in recent years and that electricity demand has historically increased substantially as the region emerges from a recession appear to justify the consideration of such an alternative forecast. However, the Siting Council notes that such a simplified methodology as that employed in the EPEC alternative forecast fails to account for potential changes over time with respect to such factors as demographics, the structure of the regional economy, the acceleration of utility investment in C&LM, technological change, and social change, all of which may affect the demand for electricity in the region. Nevertheless, the Siting Council acknowledges that a simplified methodology such as that used in the EPEC alternative forecast can be appropriate in cases where that alternative forecast is being compared to a forecast developed through a more sophisticated methodology.

Accordingly, the Siting Council finds that the EPEC alternative forecast is an acceptable high case alternative to the use of the 1990 CELT forecast.[35]

EPEC's assumptions regarding NEPOOL's required future reserve margins appear to be reasonable. The Siting Council finds that these reserve margins are conservatively low relative to expected NEPOOL reserve requirements, and therefore, appropriate for the purposes of evaluating regional need.

With regard to EPEC's choice of supply scenarios, the Siting Council finds that EPEC's seven supply scenarios provide an appropriate basis for the evaluation of resource need in this proceeding. In previous decisions, the Siting Council has criticized regional need analyses that failed to consider a full range of supply contingencies. Specifically, the Siting Council has criticized regional need analyses which have not addressed contingencies such as: (1) the timing and magnitude of supply additions or reductions in existing supplies; (2) the impacts of existing plant performance, fuel prices and utility-sponsored C&LM programs; and (3) the impact of the availability of new gas supplies in the region. West Lynn, EFSC 90-102 at 28; MASSPOWER, 20 DOMSC at 321-322; Altresco-Pittsfield, 17 DOMSC at 364-365. The Siting Council notes that, here, EPEC has presented a reasonably comprehensive set of alternative supply scenarios. Further, the Siting Council notes that EPEC's supply scenarios, together with its 1990 low C&LM forecast and its 1990 high C&LM forecast, have addressed most of the important types of contingencies identified by the Siting Council in previous reviews of regional need.

35/ The Siting Council notes that in accepting the use of a 3.2 percent annual growth rate forecast in two consecutive cases we are by no means accepting this growth rate as generally applicable. Rather, the Siting Council findings here and in EEC are based on the methodology used to develop the alternative forecast as compared to other forecasts presented in these proceedings.

However, the Siting Council notes that EPEC could have provided further support for some of its supply scenarios. Specifically, the Siting Council notes that EPEC should have presented a discussion of other types of supply contingency cases which could impact the region's supply mix and a more detailed explanation of why it selected its particular supply scenarios. Further, while EPEC identified three supply scenarios which it believed were most likely to occur, EPEC did not justify its conclusions.

Nevertheless, the Siting Council finds that the need cases developed by EPEC based on the 1990 CELT forecast, the EPEC alternative forecast, and the seven supply scenarios represent a reasonable basis for the evaluation of resource need in this proceeding.

The Siting Council notes that the need cases based on the 1990 CELT forecast indicate that the capacity of the proposed project is needed for reliability purposes in the 1994-1995 time frame. The need cases based on the 1990 low C&LM forecast and the 1990 high C&LM forecast also support a need for the proposed project in the 1994-1995 time frame. Finally, the need cases based on the EPEC alternative forecast support a need for the 146 MW of capacity represented by the proposed project beginning in 1992.

The Siting Council also notes that the load growth sensitivity analysis performed by EPEC provides a valuable insight into the sensitivity of regional need to various levels of projected load growth. In general, EPEC's load growth sensitivity analysis indicates that the projected first year of continuous need for at least 146 MW is highly sensitive to the growth rate assumed.[36] Specifically, EPEC's analysis

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36/ The Siting Council notes that EPEC's need analyses appear to indicate that the first year of continuous need for the capacity of the proposed project is much more sensitive to variations in load growth than to variations in the availability of various supply sources.

indicates a need for the facility's capacity by 1995 or earlier at an average annual demand growth rate of 1.5 percent or more. We note that this is a considerably lower rate of growth than the 3.2 percent historical rate of growth embodied in the EPEC alternative forecast. Thus, EPEC's load growth sensitivity analysis provides the Siting Council with additional confidence that there is a need for the proposed project in the 1995 time frame.

With regard to the NEPOOL resource assessments, in previous cases, the Siting Council has stated that project proponents who present NEPOOL resource assessments as part of a regional need analysis must analyze and explain fully both the resource assessment and its effect on the regional need analysis. MASSPOWER, 20 DOMSC at 322. Here, EPEC has presented a reasonably thorough explanation of the 1989 and 1990 resource assessments, the underlying assumptions and methodologies employed in these resource assessments, and a discussion of the appropriate use of their results. The Siting Council notes that EPEC's analysis of the 1990 resource assessment provides persuasive support for the practice of evaluating a variety of demand forecasts and a broad range of resource contingencies in making determinations of regional need.[37]

At the same time, the Siting Council does not agree with EPEC that the results of the 1990 resource assessment require that resource need determinations be based on achieving a 70 percent confidence level. In a previous decision, the Siting Council found that a 70 percent reliability level was reasonable for a particular utility's planning purposes. 1989 BECo Decision, 18 DOMSC at 277. However, the Siting Council also has stated that a reliability reserve which may be appropriate for a particular utility is not necessarily appropriate for addressing

37/ Since the Siting Council has found that it is inappropriate to consider the 1989 CELT forecast for the purposes of determining regional need in this proceeding, we similarly decline to consider the 1989 resource assessment.

the resource needs of an integrated power pool. EEC, EFSC 90-100 at 48; West Lynn, EFSC 90-102 at 29. While the Siting Council recognizes that it is appropriate for non-utility developers to consider some level of reliability in developing regional need analyses, EPEC has failed in this case to provide adequate documentation in support of the use of a 70 percent confidence level. In future cases, if project proponents argue for the adoption of specific reliability levels, they will be expected to provide (1) analyses of the implications of the proposed reliability levels on the regional power system, and (2) a discussion of how the proposed reliability levels relate to the contingency tests performed.

In sum, EPEC's analysis of the need for the capacity of the proposed project for reliability purposes is reasonably comprehensive. Even without the need cases developed from the 1989 and 1991 CELT forecasts, the record contains 28 distinct need cases based on four demand forecasts and seven supply scenarios. Further, the Siting Council has found that the demand and supply forecasts used to develop the need cases incorporate an appropriate range of values for evaluation, and that the range of supply scenarios paired with these forecasts are appropriately broad and representative of reasonably likely contingencies. In addition, the Siting Council notes that of the 28 need cases which the Siting Council has determined are appropriate for use in evaluating regional need in this proceeding, eight (29 percent) of the cases identify a need for at least 146 MW by 1993, 23 (82 percent) of the cases identify a need for at least 146 MW of additional generating capacity by 1994, and all 28 cases identify a need for at least 146 MW by 1995. The 1990 resource assessment provides additional evidence in support of the argument that the capacity of the proposed facility is needed by 1995. Finally, EPEC's load growth sensitivity analysis indicates that there is a need for at least 146 MW of additional capacity by 1995 in 55 of the 56 (98 percent) need cases which are based on an average annual growth rate of 1.5 percent or greater. Such results provide credible evidence of the need for at least 146 MW of additional energy resources in the 1994-1995 time frame.[38]

Accordingly, the Siting Council finds that EPEC has established that, beginning as early as 1994, and, in any event, by 1995, New England will need at least 146 MW of additional energy resources for reliability purposes.

c. New England's Need for Additional Energy Resources for Economic Efficiency Purposes

i. Description

In support of its argument that the proposed project is needed on economic efficiency grounds, EPEC provided a series of detailed dispatch analyses of the NEPOOL system, both with and without the proposed EPEC project (Exhs. HO-N-36, HO-RR-22, HO-RR-34, HO-RR-35, HO-RR-36, HO-RR-106). EPEC stated that these analyses demonstrate that the operation of the proposed facility would result in the accrual over time of significant cost savings to the region through the displacement of more expensive sources of power (Exhs. HO-N-36, HO-RR-22, HO-RR-36). These dispatch analyses were produced by a model of the NEPOOL dispatch curve developed by EPEC's consultants, Reed Consulting

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38/ The Siting Council has recently approved two other non-utility generating projects with a total capacity of 425 MW. EEC, EFSC 90-100; West Lynn, EFSC 90-102. The Siting Council notes that the capacity represented by these projects is implicitly taken into account in the need analyses prepared by EPEC by means of EPEC's assessment of the availability of committed and uncommitted NUGs. Further, the Siting Council notes that EPEC will be competing with EEC, West Lynn and other NUGs, as well as other supply and C&LM programs, to sell the uncommitted portion of their output. Moreover, Siting Council approval of a proposed project, while a significant indication of the viability of a project, does not guarantee that the project will, in fact, be built.

Group ("Reed dispatch model").[39] EPEC stated that the Reed dispatch model is based on current NEPOOL dispatch practices[40] and characteristics of existing power plants serving NEPOOL

39/ The Reed dispatch model also was used to calculate the change in the total emissions of various pollutants by NEPOOL generating sources that would result from the construction and operation of the proposed EPEC facility (Exhs. HO-N-36, HO-RR-38). See Section II.A.4.d, below, for a discussion and analysis of reduced emissions as a Massachusetts benefit.

40/ EPEC stated that the Reed dispatch model generally assumes that NEPOOL generating units would be dispatched based on "true economic dispatch" (Exh. HO-N-36, p. 2). EPEC stated that under true economic dispatch, units are dispatched in order of variable cost, with units with the lowest variable cost dispatched first (id.). EPEC explained that variable costs are the sum of variable fuel and operating costs (id., pp. 2, 3). EPEC stated that true economic dispatch does not capture the technical operating constraints experienced by power plants, but nevertheless represents a reasonable approximation of actual NEPOOL dispatch practices (id.; Tr. 3, pp. 49-51). EPEC noted that the Reed dispatch model departed from the use of true economic dispatch in the case of a number of baseload facilities which it classified as "must run" units (Tr. 3, pp. 38-45; Exh. HO-N-36, Appendix B). Such must run units were assumed not to be displaced by the proposed project in the Reed dispatch model even if the proposed EPEC project had a lower variable cost (id.).

EPEC asserted that the Reed dispatch model incorporated a number of conservative assumptions with regard to NEPOOL's dispatch practices and other factors (Exh. HO-N-36, Appendix B). These assumptions include the following: (1) nuclear facilities would not be displaced even if the proposed project's variable cost is lower; (2) all NUG facilities included in the analysis and all utility-owned hydropower facilities would operate as "must run" units, and therefore would be dispatched before the proposed project regardless of cost; (3) Ocean State Power units I and II and "net of purchases and sales" (such as the Hydro-Quebec Phase II purchase) would be dispatched before the proposed project regardless of cost; and (4) the capacity of each plant was multiplied by its target unit availability (rather than actual historical availability) to model downtime due to maintenance and forced outages (id.). EPEC stated that because of its low variable cost of 1.19 cents per kwh, the proposed project likely would be dispatched before a number of the aforementioned facilities (Tr. 3, pp. 38-43). EPEC also stated that the actual availability of various plants may be lower than the target availability of those plants (id., pp. 45).

(Exhs. HO-N-36, pp. 2-4, HO-RR-22).[41] EPEC also stated that the Reed dispatch model incorporated realistic assumptions regarding future regional load growth, fuel and operating cost escalation rates,[42] and the type(s) of future capacity which will be built to meet future regional power requirements (id.).

Specifically, EPEC stated that for each of the 20 years of the analysis, the Reed dispatch model sorted the list of NEPOOL generating units[43] by variable cost and then determined an "available capacity" value for each plant by multiplying the plant's rated capacity by its target unit availability (Exh. HO-N-36, pp. 2-3). EPEC stated that it then determined the cumulative system capacity for the NEPOOL system by summing

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41/ EPEC stated that it collected a variety of information on existing facilities such as facility type, plant name, fuel type, target unit availability, rated capacity, heat rate, pollutant emissions, and fuel and operating costs (Exh. HO-N-36, p. 2). EPEC compiled this information from NEPOOL member utilities' FERC Form 1 Reports and from several NEPOOL documents (id.).

42/ EPEC stated that power plant fuel and O&M costs were escalated each year based on projections prepared by Data Resources Inc. ("DRI") (Exh. HO-N-36, p. 2). EPEC further stated that these DRI fuel price projections were included in ComElectric's Second Request for Proposals ("RFP") for Qualifying Facilities ("QFs") and were consistent with EPEC's earlier analysis (Exh. HO-RR-41; Tr. 7, pp. 108, 109). The fuel price escalators included in the ComElectric RFP indicate that the price of medium sulfur coal is projected to increase at a significantly lower rate than either gas or oil prices (Exh. HO-RR-41).

43/ EPEC stated that it included in its dispatch list all existing units, 75 percent of all committed NUG capacity currently under development, and 50 percent of all uncommitted NUG capacity currently under development (Exh. EPEC-12, p. 16; Tr. 7, p. 102). EPEC stated that these assumptions were consistent with supply scenario 5, which it believed to be the most likely supply scenario (Exh. EPEC-12, p. 16; Tr. 3, p. 103). See Section II.A.3.b.i.(B), above, for a discussion of EPEC's supply scenarios.

the available capacity for all existing plants (id.). For years in which cumulative system capacity was determined to be less than projected peak demand, a generic new facility or facilities was added until cumulative system capacity was sufficient to meet peak requirements (id.). EPEC stated that it then compared cumulative system capacity to a simplified NEPOOL load duration curve for each year of the analysis (id.).[44] The proposed project was then inserted into the dispatch order and the Reed dispatch model was rerun in order to determine the number of hours that each plant was displaced by the proposed project in a particular year (id.). Finally, the value of the fuel which would have burned in the displaced plants and the cost of the alternative expansion plans were summed on a net present value basis over the 1993-2012 period (id.). Using this methodology, EPEC calculated the total cost savings to the region attributable to the proposed project (id., pp. 3-6).

In order to determine a reasonable range of cost savings attributable to the proposed project, EPEC performed a series of sensitivity analyses of two major assumptions: (1) the projected rate of regional load growth; and (2) the type(s) of capacity which will be built in the future to meet the region's capacity requirements (Exhs. EPEC-12, HO-RR-22, HO-RR-36). Specifically, EPEC analyzed the economic savings attributable to the proposed project for six different load growth scenarios, including four constant annual load growth scenarios (0.85 percent, 1.0 percent, 1.5 percent, and 2.0 percent), the 1990 CELT forecast of summer peak load, and the 1991 CELT forecast of summer peak load (Exhs. HO-RR-22, HO-RR-106). EPEC also examined three different regional capacity expansion scenarios:

44/ EPEC stated that it used an annual load duration curve obtained from NEPOOL which consists of 30 data points representing a summary of actual 1989 hourly load data (Exh. HO-N-36; Tr. 3, pp. 47, 68). EPEC further stated that it used this load duration curve to derive the annual load duration curve of demand in the future by uniformly increasing all data points by a particular growth rate (Exh. HO-N-36; Tr. 3, p. 64).

(1) a 100 percent oil-fired combustion turbine expansion plan ("combustion turbine expansion plan"); (2) an 85 percent gas-fired combined cycle/15 percent oil-fired combustion turbine expansion plan ("combined cycle expansion plan"); and (3) an 85 percent atmospheric fluidized bed ("AFB") coal plant/15 percent oil-fired combustion turbine expansion plan ("coal expansion plan") (Exhs. EPEC-12, p. 15, HO-RR-36).[45] Thus, EPEC estimated the economic savings attributable to the proposed project from the displacement of more expensive generation sources for a total of 18 alternative load growth/capacity

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45/ EPEC stated that the capacity costs of the generic combustion turbine additions were based on the NEPOOL deficiency charge of $98/kilowatt per year (in 1990 dollars), escalated at an annual rate of four percent, and the variable costs of the combustion turbines were based on estimates included in the NEPOOL Generation Task Force Assumptions Book (Exh. HO-RR-36; Tr. 3, pp. 58, 71, 72). EPEC further stated that the capacity and variable cost pricing structures for the generic combined cycle and coal units were based on two recent PPAs (Exh. HO-RR-36). Specifically, the cost of generic gas-fired combined cycle additions was based on a PPA that ComElectric recently signed with Dartmouth Power, and the AFB coal project costs were based on a PPA that BECo signed with Patriot Energy (id.; Tr. 7, pp. 109-111).

EPEC stated that the Dartmouth Power and Patriot Energy PPAs were the most recent PPAs available which included sufficiently detailed information on the capacity and variable costs of gas-fired combined cycle and AFB coal projects, respectively (Exh. HO-RR-36; Tr. 7, pp. 104, 105). EPEC asserted that the capacity and energy costs taken from the Dartmouth Power contract are a reasonable representation of generic gas-fired combined cycle projects, because the Dartmouth Power project has a gas supply with a low commodity cost, thereby ensuring that that project will be dispatched at a high rate and minimizing the potential displacement benefits of the proposed project (Exh. HO-RR-36). EPEC further asserted that the costs contained in the Patriot Energy PPA were typical for an AFB coal plant (Tr. 7, pp. 104-105). EPEC noted that it would have preferred to base its AFB coal plant cost estimates on the EEC project, since it is the most recent local coal project to obtain a PPA, but that it could not do so because the EEC PPA did not provide sufficient information on pricing (id.).

expansion plan scenarios.[46]

EPEC's analyses indicated that although the region would begin to accrue fuel cost savings as soon as the proposed project is placed into operation and would continue to benefit from such savings over the 20-year period of the analyses, the region would not experience net cost savings in the proposed project's first year of operation (Exhs. HO-RR-22, HO-RR-36, HO-RR-85, HO-RR-106). The analyses showed the region would experience a negative cash flow in 1993 as the result of the operation of the proposed project, because the total capacity and energy payments to EPEC would exceed the total savings to NEPOOL in that year, and depending on the scenario chosen, for several years afterwards. (id.). For example, using the 1990 CELT forecast, the analyses indicated the proposed project would produce cost savings to the region beginning in 1994 for the combined cycle expansion plan and the coal expansion plan, and beginning in 1998 under the combustion turbine expansion plan (Exhs. HO-RR-22, HO-RR-36). EPEC's analyses showed that the cost savings to the region increase with time, and that the proposed project would produce significant annual net savings to NEPOOL for all scenarios in each year during the 2001-2012 period (id.).

Over the entire 20-year period of the analyses, EPEC's calculations indicate that the total economic savings

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46/ EPEC stated that the 0.85 percent per year constant load growth scenario was developed by solving for the rate at which the economic savings from the proposed project would approach zero under its combustion turbine expansion plan scenario (Exh. HO-RR-22). EPEC asserted that 0.85 percent load growth therefore constitutes a lower bound for the load growth needed to produce net economic savings to the region as the result of the displacement of more expensive facilities by the proposed project (id.). EPEC further noted that, according to the 1990 NEPOOL resource assessment, an annual load growth in excess of 0.85 percent has a probability of occurrence of more than 90 percent (id.).

associated with the unsold portion of the project[47] would range from $3.0 million to $128.8 million[48] (in 1993 dollars), depending on the load growth rate and capacity expansion plan selected (Exhs. HO-RR-22, HO-RR-36, HO-RR-85, HO-RR-106; Tr. 3, p. 75). EPEC's analyses further indicate that the net cost savings attributable to the project increase as the selected rate of load growth increases, and that the coal expansion scenario results in higher net cost savings to the region than the cost savings resulting from the other two capacity expansion scenarios (Exhs. HO-RR-22, HO-RR-36, HO-RR-85, HO-RR-106). Table 5 presents a summary of the results of EPEC's analysis of the total economic savings to the region that would result from the displacement of more expensive power sources by the proposed project.

ii. Analysis

In the past, the Siting Council has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and the 1984 Boston Gas Decision, 11 DOMSC at 166-168, the Siting Council recognized the benefit of adding economic supplies to a specific utility system. In addition, where a non-utility developer has proposed a generating facility for a number of power purchasers that are as yet unknown, or for purchasers

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47/ EPEC calculated regional cost savings for only the unsold portion of the plant's capacity rather than for the full capacity of the proposed project based on the theory that the existence of the NEPCo PPA had demonstrated the need for that portion of the proposed project's output (Exhs. HO-RR-22, HO-RR-36).

48/ EPEC presented slightly revised results for its constant growth load cases but provided no explanation regarding the reasons for such changes (Exh. HO-RR-106). Given the small size of these changes and their undocumented nature, the Siting Council does not consider them further in its analysis.

with retail service territories outside of Massachusetts, need may be established on either reliability or economic efficiency grounds. EEC, EFSC 90-100 at 15-49; West Lynn, EFSC 90-102 at 10-32; MASSPOWER, 20 DOMSC at 314-323; Altresco-Pittsfield, 17 DOMSC at 361-365; NEA, 16 DOMSC at 344-360.

In previous reviews of non-utility proposals to construct electric generation projects, project proponents have argued that additional energy resources were needed in the region based on economic efficiency grounds, i.e., that the construction and operation of a particular project would result in a significant reduction in the total cost of generating power in the New England region through the displacement of more expensive sources of power. EEC, EFSC 90-100 at 18-19; West Lynn, EFSC 90-102 at 10; MASSPOWER, 20 DOMSC at 19. In each of these cases, the Siting Council rejected the non-utility proponents argument that additional energy resources were needed for economic efficiency purposes.

In MASSPOWER, the Siting Council stated that the use of a levelized cost methodology to develop estimates of economic efficiency savings generally was sound, but that the results of such a methodology could not be evaluated without a full description of underlying data and assumptions (20 DOMSC at 19). In both West Lynn, EFSC 90-102 at 32, and MASSPOWER, 20 DOMSC at 19, the Siting Council found that the project proponent had failed to provide adequate analyses and documentation in support of assertions that their respective projects were needed on economic efficiency grounds.

In EEC, the Siting Council noted that the non-utility proponent's analysis of the economic efficiency benefits associated with its proposed project was the most comprehensive economic efficiency analysis presented up to that time in a Siting Council proceeding (EFSC 90-100 at 49). The Siting Council also noted that EEC's analysis appeared to address many of the concerns raised by the Siting Council in previous non-utility generating facility cases where economic efficiency arguments had been presented. Id. Nevertheless, the Siting

Council found that EEC's economic efficiency argument could not be accepted for the purposes of determining need on economic efficiency grounds in that proceeding because EEC's analysis was based on some of the same underlying assumptions as the 1991 CELT forecast, a forecast which the Siting Council had rejected for the purposes of evaluating need in that proceeding. Id.[49]

Here, EPEC has presented a comprehensive analysis to support its arguments regarding the need for its proposed project on economic efficiency grounds. Consequently, for the first time, the Siting Council is presented with a case in which it can evaluate the need for a non-utility generating project on economic efficiency grounds.

In evaluating an argument for regional need for a specific non-utility project on economic efficiency grounds, the Siting Council must consider both the generic implications of such a need finding as well as the project-specific attributes of such a finding. The Siting Council notes that our analysis of regional need on reliability grounds addresses the generic need for additional energy resources, as opposed to the need for a specific project. In contrast, the only instances in which the Siting Council has found a need for a specific NUG project or portion of such a project on economic efficiency grounds have been when such projects have had signed and approved PPAs, which we have determined to represent prima facie evidence of need for the contracted power on economic efficiency grounds by the particular utility systems with whom PPAs are executed. EEC, EFSC 90-100 at 50-52; Altresco-Pittsfield, 17 DOMSC at 366-367; NEA, 16 DOMSC at 357-360.

49/ Here, we also have found that the 1991 CELT forecast should not be used for the purposes of evaluating regional need for reliability purposes. See Section II.A.3.b.iii, above. Accordingly, in our assessment of the need for the proposed project for economic efficiency purposes, we decline to consider scenarios based on the 1991 CELT forecast. However, EPEC has provided 15 other scenarios based on five alternative load forecasts, which provide a sufficient basis for evaluating EPEC's arguments on the need for the proposed project on economic efficiency grounds.

The Siting Council recognizes that it may be argued that a generic regional need for additional energy resources on economic efficiency grounds always exists. Specifically, it may be argued that there is a regional need for additional energy resources on economic efficiency grounds whenever the region would benefit economically from the addition of energy resources which result in a lower total cost of power generation in the region.

Clearly, however, accepting such a generic economic efficiency argument as determinative on regional need would raise potentially serious conflicts with our overall mandate to ensure a necessary energy supply at least cost and least environmental impact. In fact, NEPOOL's dispatch practices, on which such regional need arguments are based, emphasize this inconsistency as power plants are dispatched solely on economic cost without consideration of environmental impacts.[50]

In addition, the very nature of the analyses necessary to establish regional need on economic efficiency grounds, i.e., comprehensive analyses of NEPOOL dispatch both with and without a proposed project, makes any such argument extremely project-specific. This would necessarily lead to a finding of regional need for a specific project on economic efficiency grounds rather than a generic finding of regional need for additional energy resources on economic efficiency grounds.

The Siting Council notes that such a project-specific finding would not be inconsistent with our standard and with our findings in previous cases that signed and approved PPAs constitute prima facie evidence for the contracted power on economic efficiency grounds. However, we note that unlike economic efficiency gains associated with specific PPAs, regional economic efficiency gains are not contractually

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50/ The Siting Council recognizes that the addition of clean, cost-effective resources to the regional energy mix can have positive environmental impacts on the region indirectly through the displacement of more polluting resources. See Section II.A.4.d, below.

guaranteed.

The Siting Council reiterates its recognition that regional need may be established on economic efficiency grounds. However, we note that any economic efficiency gains that may result from a particular project, because of their project-specific nature, cannot be viewed in a vacuum; rather they must be viewed within the context of other attributes of the project. Therefore, in determining whether regional need on economic efficiency grounds has been adequately established by a project proponent, the significance of such economic efficiency gains and the degree to which such gains are assured will be critical factors in our review. Further, the Siting Council will evaluate on a case by case basis whether the magnitude and timing of the economic efficiency gains identified are adequate to establish regional need on economic efficiency grounds.

Here, EPEC has provided a detailed description of the methodology and assumptions that it has employed in its economic efficiency analysis. Moreover, although the methodology employed by EPEC and its consultant relies on certain simplifying assumptions, such as the use of true economic dispatch and a simplified NEPOOL load duration curve, EPEC's overall approach appears to be methodologically sound. Thus, the EPEC analysis addresses many of the concerns raised by the Siting Council in previous NUG cases where economic efficiency arguments have been presented. West Lynn, EFSC 90-102 at 32; MASSPOWER, 20 DOMSC at 19.

Further, the assumptions used in EPEC's analysis appear to be generally reasonable, although EPEC could have provided better documentation in support of certain assumptions, such as EPEC's choice of generic generation plant costs, fuel and O&M escalators, and EPEC's application of a constant growth rate to all points on the 1989 NEPOOL load duration curve to produce the NEPOOL load duration curve in future years. The Siting Council notes that regional peak load may grow at significantly different rates than average or minimum load over time. In the future, project proponents that attempt to establish regional need for additional energy resources on economic efficiency grounds will be expected to address these matters more comprehensively in their analyses.

Nevertheless, EPEC's analysis represents an acceptable methodological approach to assessing the regional need for additional energy resources on economic efficiency grounds. For example, EPEC's use of multiple scenarios provides the Siting Council with important insight into the sensitivity of the results of EPEC's analysis to variations in important assumptions which are subject to some degree of uncertainty. In particular, EPEC's sensitivity analyses indicate that the proposed project will generate significant and quantifiable economic savings to the region over time under a broad range of potential load growth scenarios and assumptions regarding the type(s) of new generation capacity that will be built in the region in the future.

In considering the three specific alternative capacity expansion plans provided by EPEC, the Siting Council notes that a realistic capacity expansion plan should feature an appropriate mix of baseload and peak-load facilities to meet future regional requirements. While the combined cycle expansion plan and the coal expansion plan meet this test, the combustion turbine expansion plan, which includes no baseload units, does not appear to represent a reasonable resource mix. As a result, we decline to consider the five scenarios based on the combustion turbine expansion plan, and instead focus our review on the ten remaining scenarios based on the combined cycle and coal expansion plans.

In regard to the timing of the economic efficiency gains, EPEC's analyses indicate that the region would not begin to experience cost savings as the result of the operation of the proposed project in its first year of operation. Rather, in 1993, and depending on the scenario, for several years afterwards, the total capacity and energy payments to EPEC would exceed the total cost savings to the region. Specifically, the combined cycle and coal expansion plans, when combined with the

1990 CELT forecast, indicate economic efficiency savings to the region beginning in 1994. The other load growth cases, when combined with these two capacity expansion plans, indicate economic efficiency savings to the region beginning in 1995 under the 2.0 percent constant load growth scenario, in 1996 under the 1.5 percent constant load growth scenario, in 1998 under the 1.0 percent constant load growth scenario, and in 1999 under the 0.85 percent constant load growth scenario. The first year of net cost savings to the region under various load growth and capacity expansion scenarios is summarized in Table 6.

The Siting Council notes that the record in this proceeding indicates that there is a high probability of annual regional load growth exceeding 1.5 percent annually on average. See Section II.A.3.b, above. Assuming an annual load growth rate of 1.5 percent or higher, the record indicates that the proposed project would generate substantial cost savings for the region, on the order of $62 to $129 million over 20 years depending on the scenario selected. Further, the record indicates that the proposed project would generate cost savings to the region even if regional load growth is as low as 0.85 percent annually.

In addition, the record indicates that the proposed project would likely begin to generate cost savings to the region in the 1994-1996 period, assuming that annual regional load growth is 1.5 percent annually or higher. The likelihood that the region will begin to accrue cost savings as the result of the operation of the proposed project within one to three years of the planned startup of that project provides the Siting Council with a high degree of confidence that such projected cost savings will actually be realized by the region.

Accordingly, the Siting Council finds that EPEC has established that New England would realize economic savings of substantial magnitude from the operation of the proposed project over the likely term of its PPAs,[51] and that these savings would begin to accrue on a continuous basis beginning as early as 1994, and, in any event, by 1996.

Accordingly, the Siting Council finds that EPEC has established that beginning as early as 1994, and in any event by 1996, New England will need at least 146 MW of the additional energy resources from the proposed project for economic efficiency purposes.

d. Conclusions on New England's Need for Additional Energy Resources

The Siting Council has found that EPEC has established that (1) beginning as early as 1994, and, in any event, by 1995, New England will need at least 146 MW of additional energy resources for reliability purposes, and (2) New England will need at least 146 MW of the additional energy resources from the proposed project for economic efficiency purposes beginning as early as 1994, and in any event by 1996.

Accordingly, the Siting Council finds that EPEC has established that New England needs at least 146 MW of additional energy resources for reliability or economic efficiency purposes beginning in the 1994 to 1995 period, and beyond.

4. Benefits to Massachusetts

In NEA, the Siting Council found that a non-utility developer proposing the addition of energy resources in the Commonwealth must demonstrate that its proposed project offers reliability or economic efficiency benefits to the Commonwealth in sufficient magnitude to offset the impact on the

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51/ The NEPCo PPA is for a term of 20 years, coinciding with the term examined by EPEC in its analysis of need for economic efficiency purposes (Exh. EPEC-2, Appendix B). The Siting Council notes that NEPCo does have the right to terminate the PPA after 15 years, and that although the Siting Council's analysis does rely on EPEC's calculations of the net benefits to the region over 20 years, many of EPEC's scenarios also demonstrate significant net economic benefits to the region over a 15-year term as well.

Commonwealth's resources of construction and operation of the proposed facilities (16 DOMSC at 349). In Altresco-Pittsfield, the Siting Council found that a non-utility developer also may demonstrate benefits to the Commonwealth based on economic grounds outside of a PPA or on environmental grounds (17 DOMSC at 368-369).[52] Therefore, having established above that New England will need at least 146 MW of additional energy resources for reliability and economic efficiency purposes beginning in the 1994 to 1995 period and beyond, the Siting Council determines here whether the proposed project is likely to provide reliability, economic, environmental, or other benefits to Massachusetts.

a. Power Sales

In NEA, the Siting Council found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost effective QF resources to its utilities' supply mix (16 DOMSC at 358). In that case, the Siting Council also found (1) that a signed and approved PPA between a QF and an electric utility constitutes *prima facie* evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes *prima facie* evidence of the need for additional energy resources for reliability purposes. Id.

Here, the Siting Council is considering the petition of an IPP for the first time. EPEC stated that FERC approval is required for any PPA between an IPP and an electric utility (Tr. 2, p. 30). As noted above, EPEC has provided a signed PPA with NEPCo for 83.5 MW, or 57.2 percent of the proposed project's capacity of 146 MW (Exh. EPEC-2, Appendix B).

52/ In Turners Falls, the Siting Council found that a non-utility developer also may demonstrate benefits to the Commonwealth in the form of community benefits (18 DOMSC at 162-164).

The NEPCo PPA provides for both capacity and energy payments to EPEC (id.). EPEC also provided a copy of a final FERC order issued on August 16, 1990 accepting the rates set forth in the NEPCo PPA and granting EPEC waivers from various FERC regulations under the Federal Power Act (Exh. HO-N-6).

The record indicates that in its decision to approve the NEPCo PPA, FERC considered NEPCo's project selection process, the provisions of the NEPCo PPA, including rate structure, and EPEC's lack of market power (id.). The Siting Council recognizes that the FERC approval process for PPAs between electric utilities and IPPs is, for all intents and purposes, comparable to the MDPU review process for PPAs between electric utilities and QF's.

EPEC argued that its proposed project is consistent with the energy needs and resource use and development policies of the Commonwealth, and that the NEPCo PPA demonstrates that Massachusetts will benefit from the additional energy resources represented by the proposed project for both reliability and economic efficiency purposes (EPEC Initial Brief, p. I-26). EPEC indicated that the power purchased from EPEC by NEPCo would be resold to NEPCo's three affiliated retail companies, including Massachusetts Electric Company ("MECo"), on a pro rata basis (Exhs. HO-N-7, HO-N-32). EPEC further indicated that the pro rata share of MECo's energy purchases of all NEPCo energy sales was approximately 74 percent in 1989 (Exh. HO-N-7). EPEC further stated that the NEPCo PPA would provide NEPCo with power at a price below its avoided costs (Exh. EPEC-1, pp. II-32 to II-34).[53]

Accordingly, based on the foregoing, the Siting Council finds that EPEC has established that MECo's ratepayers are likely to receive economic efficiency and reliability benefits

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53/ EPEC's witness, Mr. Hachey, stated that the avoided cost methodology employed by NEPCo in its FERC filing is similar to the methodology employed by NEPCo in a QF contract recently approved by the MDPU (Exhs. HO-RR-12, HO-RR-13; Tr. 2, pp. 33, 34).

from the proposed additional power resources. Accordingly, the Siting Council finds that EPEC has established that its proposed project offers economic efficiency and reliability benefits to Massachusetts through its NEPCo PPA.

b. Other Economic Benefits

EPEC argued that the proposed project would provide additional economic benefits to Massachusetts and the Town of Milford in the form of a lump sum monetary gift, additional tax revenues, revenues from the purchase of wastewater effluent, and employment during the construction and operation of the proposed project (EPEC Initial Brief, pp. II-28 to II-30).

Specifically, EPEC stated that it would provide an unrestricted gift to the Town of Milford of $800,000, annual property tax revenues of more than $1 million, and an annual payment of approximately $200,000 for the purchase of wastewater effluent from the MWTP (Exh. EPEC-1, pp. II-34, II-35; Tr. 9, pp. 123-125, 143-145).[54] EPEC stated that the payments that it would make to the Town of Milford are not passed through to power purchasers but rather reduce EPEC's potential profits from the proposed project (Tr. 1, pp. 144, 145). In addition, EPEC stated that the proposed project would employ up to 200 people during construction and 30 people during operation, and that it would attempt to employ local workers as much as possible (Exh. EPEC-1, pp. II-34, II-35).

EPEC's witness, Mr. DeBartolomeis, supported EPEC's assertions in this regard, stating that the EPEC project "represents a substantial economic benefit to the community. Enron would become far and away the largest taxpayer to the Town of Milford, bringing much needed new tax revenue to the Town which will be used for the betterment of the community's

54/ The wastewater effluent from the MWTP currently is discharged to Charles River (Exh. EPEC-1, p. III-35). See Section III.E.2.b, below, for a further description of EPEC's use of this wastewater effluent.

schools, services and infrastructure" (Exh. EPEC-16, pp. 4, 5; Tr. 9, pp. 121, 122).

The Siting Council notes that the construction and operation of new generating facilities typically results in the creation of jobs, new tax revenues and an overall positive impact on the local economy through the local purchase of services and materials. Such benefits may be considered to be "generic" to new generating facilities in a manner similar to the "generic" benefit represented by the addition of cost-effective resources to the regional supply mix, and therefore, typically would not represent significant Massachusetts benefits consistent with our Massachusetts benefits standard. The Siting Council notes, however, that in the instant case, the record indicates that the additional economic benefits described by EPEC above will provide a significant economic boost to the Town of Milford. For example, EPEC's lump sum payment to the Town of Milford and the revenues which Milford will receive from the sale of the MWTP effluent constitute significant economic benefits to the local community which exceed the generic level of economic benefits associated with the construction and operation of a typical electric generation project.

Accordingly, the Siting Council finds that the proposed project would provide additional economic benefits to the Town of Milford and Massachusetts through jobs, tax revenues, a lump sum payment, and revenues from the sale of wastewater effluent.[55]

c. Transmission Benefits

EPEC argued that the proposed project would provide significant transmission benefits to Massachusetts as a direct result of its location in the eastern section of the Rhode Island-Eastern Massachusetts-Vermont Energy Control Area

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55/ The Siting Council notes, however, that such benefits, where established, will rarely, if ever, be sufficient on their own to satisfy our Massachusetts benefits test.

("REMVEC") (EPEC Initial Brief, p. II-27).[56]

EPEC stated that the eastern REMVEC region has experienced electricity transmission problems in the recent past as the result of the absence of both sufficient "real power" and "reactive power" to serve local load (Exh. EPEC-1, p. II-31).[57] EPEC stated that these transmission problems have resulted in the frequent use by NEPOOL of emergency actions such as voltage reductions and requests for voluntary load curtailment, primarily during summer peak load periods in the eastern REMVEC area (id.).

EPEC also stated that several new generation facilities, including the Ocean State Power plant, are now under construction or being planned for the eastern REMVEC region, and that electric utilities in eastern REMVEC have initiated a program of capacitor installation on the transmission system to increase the amount of reactive power in the region (id., pp. II-31, II-32; Exh. HO-RR-27; Tr. 2, pp. 124, 125). EPEC contended that, even with such planned facilities, eastern REMVEC is likely to continue to experience transmission problems in the future (Tr. 2, pp. 124, 125).

In support of this contention, EPEC cited an analysis performed on behalf of the New England Cogeneration Association and submitted to FERC in May 1990 (id.; Exh. HO-RR-27). This analysis concluded that large capacity deficiencies will exist in eastern REMVEC throughout the 1990s and that such deficiencies would not be alleviated even if 100 percent of all existing, committed and uncommitted NUGs are assumed to be operational (Exh. HO-RR-27, pp. 6-9).

56/ REMVEC is one of the energy control satellite areas of the New England Power Exchange ("NEPEX"), which is NEPOOL's dispatching and operating branch (Exh. HO-N-17). Eastern REMVEC generally refers to that portion of the REMVEC region which excludes Vermont (id.).

57/ EPEC stated that "real power" is measured in watts and "reactive power," which is required to maintain voltage and stability on a transmission system, is measured in VARS (Exh. EPEC-1, p. II-31).

EPEC also cited a report by the Massachusetts Executive Office of Energy Resources ("MEOER report") which endorses the siting of new electric generation facilities in eastern Massachusetts as one of several means of enhancing the reliability of the electric transmission system in that region (Exh. EPEC-1, pp. II-32).[58]

EPEC asserted that the proposed project, through its proximity to load centers in southeastern Massachusetts, would serve to reduce the transmission constraints associated with the regional transmission system, thereby helping to alleviate the reliability problems in that area (id.). Specifically, EPEC stated that the proposed project would supply additional realpower and reactive power for local voltage support, thereby reducing the need to import real power into the region and improving the overall reliability of the regional electricity supply network (id.).

In Turners Falls, the Siting Council found that, in order for transmission system benefits to meet our Massachusetts benefits standard, such benefits must be significant and carefully documented (18 DOMSC at 159). In that decision, the Siting Council found that, while the record indicated that some transmission-related benefits might occur, the project proponent did not provide a detailed, quantitative analysis of such benefits. Id. Therefore, the Siting Council concluded that it could not find that such indirect transmission benefits would constitute a significant benefit for Massachusetts. Id.

In EEC, the Siting Council noted that in each of the cases where Massachusetts benefits have been found, those benefits have been (1) tangible, project-specific benefits which flowed directly to Massachusetts ratepayers, businesses, or communities, and (2) were guaranteed, quantifiable, and likely

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58/ The Siting Council hereby takes administrative notice of this report, entitled "Developing Energy Resources: A Five Point Plan," Massachusetts Executive Office of Energy Resources, December, 1988. The Massachusetts Executive Office of Energy Resources is now the Division of Energy Resources within the Executive Office of Economic Affairs.

to continue throughout the life of the project (EFSC 90-100 at 60). In EEC, the Siting Council also found that, based on detailed load flow analyses provided by the project proponent, the addition of the 300 MW EEC facility would provide a significant additional level of protection to the southeastern Massachusetts bulk power system and thereby provide direct benefits to the electric customers in that region (EFSC 90-100 at 67-69). In making this finding, the Siting Council was persuaded by the project-specific, quantifiable nature of EEC's analysis.

Here, while the proposed project is located in eastern REMVEC (as was the EEC project), EPEC has provided only general, non-project-specific information regarding the potential transmission benefits of the proposed project. While EPEC has demonstrated that the addition of generic electric generation capacity in the eastern REMVEC region would likely improve the reliability of the transmission system in that region, EPEC has failed to provide detailed load flow analyses which would allow the Siting Council to determine the level of reliability benefits associated directly with the proposed project. The Siting Council notes that even in a region which is generally acknowledged to have transmission problems, the degree to which a proposed new facility will ameliorate those problems may be strongly dependent on the specific location and technical details of that facility.

Accordingly, based on the foregoing, the Siting Council finds that EPEC has failed to establish that that its proposed project offers reliability benefits to Massachusetts as a result of the impact of the operation of the proposed project on the transmission system in eastern REMVEC.

d. Environmental Benefits

EPEC argued that the proposed project would provide Massachusetts and the New England region with immediate and quantifiable environmental benefits in the form of reduced air emissions as the result of displacing the emissions of a mix of existing generation plants in the NEPOOL dispatch order (EPEC Initial Brief, pp. II-26, II-27).

In support of this assertion, EPEC provided calculations of the annual emissions of seven air pollutants -- (1) sulfur dioxide ("SO_2"); (2) nitrogen oxides ("NO_x"); (3) carbon monoxide ("CO"); (4) volatile organic compounds ("VOCs"); (5) particulates; (6) methane; and (7) carbon dioxide ("CO_2") -- for individual generating facilities and for NEPOOL as a whole (Exh. HO-RR-38).[59] EPEC compared the total emissions of each of these pollutants with and without the proposed project in the NEPOOL dispatch in order to estimate the net impact that the proposed project would have on total emissions in Massachusetts and the region (id.).

EPEC's analysis indicates that the operation of the proposed project would result in a reduction of total SO_2, NO_x, particulate, and methane emissions from generation facilities located in Massachusetts, and in a reduction in the emissions of all examined pollutants, with the possible

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59/ EPEC stated that it calculated emission changes for each pollutant included in the Department of Public Utilities' Final Order on IRM Rulemaking, D.P.U. 89-239 (1990) ("D.P.U. 89-239") for which emission factors were available (Exh. HO-RR-38).

EPEC further stated that the methodology and set of assumptions that it used to estimate potential emission reductions associated with the dispatch of the proposed project were consistent with the methodology and assumptions that it used to estimate the potential cost savings associated with that dispatch (id.). See Section II.A.3.c, above for a detailed description of EPEC's analysis of the potential cost savings to the region from the displacement of more expensive generation by the proposed project.

EPEC presented environmental calculations for four future years -- 1993, 1997, 2002, and 2012 -- and assumed three alternative capacity expansion plans to meet projected incremental generation requirements. See Section II.A.3.c.i, above, for a description of these three capacity expansion plans.

exception of VOCs,[60] in the region as a whole (id.).[61] EPEC's calculations also indicate that total CO, CO_2 and VOC emissions from generating facilities located within Massachusetts would increase as the result of the operation of the proposed project (id.). See Table 7.

The Siting Council previously has held that a project proponent must provide full documentation of its assumptions pertaining to the potential environmental benefits resulting from the displacement of other generation facilities by the proposed project. EEC, EFSC 90-100 at 71; West Lynn, EFSC 90-102 at 44; MASSPOWER, 20 DOMSC at 388; Altresco-Pittsfield, 17 DOMSC at 400. In each of these cases, however, the Siting Council found that the project proponent's analysis lacked sufficient documentation to support their arguments. In West Lynn, the Siting Council noted that the project proponent failed to document key assumptions regarding potential capacity displacement, including NEPOOL dispatch procedures, plant availability projections, fuel price projections, reserve margin projections, transmission system capability estimates, and likely revisions to environmental permitting (EFSC 90-102 at 44). In EEC, the Siting Council found that while the project proponent had provided a comprehensive analysis of the regional air emission impacts from the dispatch of its project, the proponent failed to adequately document how and to what extent those regional benefits would

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60/ EPEC stated that small net increases in region-wide VOC emissions from electricity generation occurred in certain scenarios because EPEC's emission rates were maximum figures taken from manufacturer's guarantees, whereas the emission rates for new generic coal-fired plants represent typical expected emissions (Exh. HO-RR-38). EPEC stated that if emission rates were prepared on the same basis for both types of plants, the result would likely be a reduction in region-wide VOC emissions in all cases (id.).

61/ EPEC stated that, in general, the largest regional emission reductions occurred when combustion turbines were used as incremental units in the analysis, and the smallest reductions were seen when combined-cycle units were used as incremental units (Tr. 7, pp. 89, 90).

accrue to Massachusetts (EFSC 90-100 at 71-73).

Here, EPEC has provided the Siting Council with the most comprehensive analysis of state and regional emission reductions seen to date in a Siting Council proceeding on a non-utility generation facility. This analysis includes sufficient documentation regarding the methodology and assumptions used in the calculations of the net impact that the proposed project would have on total emissions from generation facilities located in both Massachusetts and the New England region as a whole for the Siting Council to be able to evaluate the project-specific benefits from the proposed project. Thus, EPEC has documented many of the key assumptions which the Siting Council noted in West Lynn, EFSC 90-102 at 44. Moreover, the methodology and assumptions employed by EPEC in its emissions analysis appear to be reasonable.[62]

For the purposes of assessing potential benefits to Massachusetts, the Siting Council here focuses primarily on EPEC's calculations of the net impact that the proposed project would have on the total emissions from generating facilities located in Massachusetts.[63] EPEC's analysis indicates that the operation of the proposed project would clearly reduce the net emissions in Massachusetts of four of the seven pollutants analyzed: SO_2, NO_x, particulates, and methane. These

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62/ The Siting Council notes that EPEC's methodology and assumptions are essentially identical to those used by EPEC in support of its argument that the proposed facility is needed on economic efficiency grounds. The Siting Council addresses this methodology and assumptions in detail in Section II.A.3.c, above.

63/ EPEC provided no evidence regarding the potential benefits to Massachusetts from reduced emissions by existing out-of-state generation facilities or from reduced emissions from required new generation units. The Siting Council acknowledges that air pollution does not recognize state borders and that emission reductions in other states in the region may benefit Massachusetts' citizens. The Siting Council also recognizes that, to the extent that new generation units are located in Massachusetts, emission reductions from such sources also will benefit Massachusetts' citizens. Nevertheless, the Siting Council requires that project proponents provide carefully documented evidence that demonstrates significant benefits to the Commonwealth.

benefits are partially offset by the higher net Massachusetts emissions of three other pollutants. The Siting Council notes, however, that emissions of three of the pollutants of greatest concern to regional acid rain and ozone problems, i.e., SO_2, NO_x and particulates, would be reduced significantly by the operation of the proposed project. Moreover, EPEC's analysis indicates that emission reductions from the proposed project would generally increase over time, thereby providing the Siting Council with additional confidence that Massachusetts would receive significant environmental benefits over time from the operation of the proposed project.

In addition, by providing analyses of net air emissions using three different types of technologies and fuels for new plants, EPEC has demonstrated that the operation of the proposed project would result in net emission reductions of SO_2, NO_x and other pollutants across a reasonable range of possible future scenarios. The Siting Council notes, however, that EPEC has failed to analyze the net emissions impacts of potential changes in other important assumptions subject to uncertainty, such as changes in relative fuel prices and environmental regulations, which could influence the dispatch order and emissions of existing generation facilities. In future cases, the Siting Council will require project proponents seeking to establish Massachusetts benefits in the form of net emission reductions to provide additional information regarding the sensitivity of the results of such analyses to significant sources of uncertainty.

Nevertheless, based on the foregoing, the Siting Council finds that EPEC has established that its proposed project would provide Massachusetts with environmental benefits relating to air quality as a result of the impact of the operation of the proposed project on the net emissions from generation facilities located in Massachusetts.

e. Conclusions on the Benefits to Massachusetts

The Siting Council has found that EPEC has established that the proposed project: (1) offers economic efficiency and reliability benefits to Massachusetts through it's NEPCo PPA;

(2) would provide additional economic benefits to the Town of Milford and Massachusetts through jobs, tax revenues, a lump sum payment, and revenues from the sale of wastewater effluent; and (3) would provide Massachusetts with environmental benefits relating to air quality as a result of the impact of the operation of the proposed project on the net emissions from generation facilities located in Massachusetts. The Siting Council has also found that EPEC has failed to establish that its proposed project offers reliability benefits to Massachusetts as a result of the impact of the operation of the proposed project on the transmission system in eastern REMVEC.

Based on the foregoing, the Siting Council finds that EPEC has established that the proposed project would provide benefits to the Commonwealth of sufficient magnitude to offset the impacts on the Commonwealth's resources from construction and operation of the proposed project.

5. Conclusions on Need

The Siting Council has found that EPEC has established that (1) New England needs at least 146 MW of additional energy resources for reliability or economic efficiency purposes beginning in the 1994 to 1995 period, and beyond, and (2) the proposed project will provide benefits to the Commonwealth of sufficient magnitude to offset the impacts on the Commonwealth's resources from the construction and operation of the proposed project.

The Siting Council notes that the proposed project is scheduled to commence operation in 1993. However, EPEC's regional need analyses do not demonstrate need on reliability or economic efficiency grounds until at least 1994 and as late as 1995. Nevertheless, in light of: (1) EPEC's PPA for 57 percent of the output from the proposed project; (2) our finding of need on reliability grounds beginning in the 1994 to 1995 period; and (3) our finding of need on economic efficiency grounds beginning in the 1994 to 1996 period, the Siting Council finds that EPEC has established that there is a need for the additional energy resources from the proposed project.

B. Project Approach

1. Standard of Review

a. Development of Standard

The Siting Council, pursuant to G.L. c. 164, secs. 69H and 69J, is required 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 [electricity or gas], (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[64]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need and in terms of cost, environmental impact and reliability. New England Power Company, EFSC 89-24A, pp. 31-47 (1991) ("1991 NEPCo Decision"); Altresco-Pittsfield, 17 DOMSC at 370-378; NEA; 16 DOMSC at 360-380; 1986 CELCO/ComElectric Decision, 15 DOMSC at 212-218; 1985 MECo/NEPCo Decision, 13 DOMSC at 141-183; 1985 BECo Decision, 13 DOMSC at 74-81. Additionally, where a non-utility developer proposes to construct a generating facility in Massachusetts, the Siting Council determines whether the proposed project offers power at a cost below the purchasing utility's avoided cost. EEC, EFSC 90-100 at 75; West Lynn, EFSC 90-102 at 50 n 27, 55 n 30; MASSPOWER, 20 DOMSC at 341-343; Altresco-Pittsfield, 17 DOMSC at 372-374; NEA, 16 DOMSC at 360-364.

In past reviews of proposals of non-utility developers to construct generating facilities, the Siting Council has focused

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64/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." The Siting Council reviews EPEC's primary site as well as other site locations in Section III, below.

its evaluation on the comparison of the applicant's proposed generating technology and other generating technologies capable of delivering necessary energy resources. MASSPOWER, 20 DOMSC at 337-352; Altresco-Pittsfield, 17 DOMSC at 370-377; NEA, 16 DOMSC at 360-380.

In MASSPOWER, however, the Siting Council stated its concerns with a method that analyzes various project approaches based exclusively on a comparison of technologies (20 DOMSC at 349). First, the Siting Council stated that a review of NUG proposals based exclusively on a comparison of technologies is somewhat incompatible with our review of proposals filed by utilities to construct facilities. Id. at 350. In those reviews, a utility also is required to show that its proposed project approach is superior to alternate approaches in terms of cost, environmental impact, reliability, and meeting an identified need. However, the Siting Council reviews utility proposals within the context of a utility's overall supply planning process. Id. Thus, the Siting Council could determine whether the utility's decision to pursue the proposed project was the result of a process which fully evaluated a comprehensive range of resource options, including C&LM, on an equal footing, and whether the proposed project represented the least-cost, least-environmental-impact approach available to the utility. Id.

Second, the Siting Council stated in MASSPOWER that a technology-based review of project approaches in non-utility cases fails to evaluate a complete range of project approaches (20 DOMSC at 351). A review which compares different technologies for cogeneration projects ignores several other generic approaches to meeting a need for additional energy resources, such as C&LM, smaller generating projects, or power purchases from other states or regions. Id. In stating this concern, however, the Siting Council recognized that it is inappropriate to require a non-utility developer to establish that it has selected a superior project approach from among a full range of resource options when the non-utility developer only has full access to data for one option -- its proposed project. Nonetheless, the Siting Council stated that the fact that a non-utility developer does not have access to a full range of resource options does not mean that the Siting Council is any less committed to ensuring that the developer's proposed project is superior to alternate project approaches in terms of cost, environmental impact, reliability, and meeting the identified need. Id.

Therefore, in MASSPOWER, the Siting Council stated that, in future cases, it would consider different methods of reviewing whether a non-utility developer's project proposal is superior to alternate project approaches in terms of environmental impact, reliability and meeting the identified need, and the tradeoffs of each of these criteria with cost (20 DOMSC at 351).[65] The Siting Council also stated that, in formulating a new standard of review in this area, we would attempt to find mechanisms which (1) allow the Siting Council to compare proposals by non-utility developers with a full range of resource options available to the state and region, and (2) place greater emphasis on determining whether a non-utility developer's proposed project is consistent with our statutory mandate and the resource use and development policies of the Commonwealth.[66] Id. at 351-352.

In West Lynn, the Siting Council further developed the project approach standard consistent with our discussion in

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65/ With respect to cost, the Siting Council found that the requirement that a non-utility developer establish that its proposed project offers power below purchasing utilities' avoided costs remains essential to our review of a proposed project. MASSPOWER, 20 DOMSC at 351. The Siting Council now addresses this requirement in our analysis of project viability. See Section II.C.2, below.

66/ In addition to notifying the parties in this proceeding of the intent to formulate a new standard of review, the Siting Council also notified the parties in the West Lynn and EEC proceedings, which were pending at that time. See October 4, 1990 Siting Council Memorandum. West Lynn and EEC are non-utility developers, and both of the proceedings involved proposals to construct generation facilities.

MASSPOWER (EFSC 90-102 at 52-57). The West Lynn decision is discussed in Section II.B.1.c, below.

b. Responses of the Parties to the Development of the Project Approach Standard

In the instant case, EPEC responded to the Siting Council's request to address the development of the project approach standard by providing supplemental direct testimony by Wayne J. Oliver (Exhs. EPEC-7, EPEC-12). None of the other parties to this proceeding addressed this issue.

EPEC suggested that a three-part project approach standard be adopted by the Siting Council (Exhs. EPEC-7, pp. 5, 6, EPEC-12, pp. 2, 6). Specifically, EPEC's proposed standard would require: (1) a determination of whether the proposed project is consistent with state or regional policies regarding the need for resources, cost of various options, diversity of resources, consistency of environmental objectives, and other policy goals; (2) a determination of whether the proposed project is consistent with the least-cost planning criteria and objectives of purchasing utilities, such as diversity of supply, lower economic cost, minimization of environmental impacts, and rate stability;[67] and (3) a determination that the proposed project is reasonably competitive [68] against

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67/ EPEC noted that, in general, state policy and electric company planning criteria should not be in conflict since both are directed at the goal of creating least-cost supply plans (Exh. EPEC-12, pp. 2, 10). EPEC indicated, however, that often there is an imperfect fit between state policy and utility planning criteria that must be resolved with formal proceedings and orders (id., p. 10).

68/ EPEC stated that a determination of a proposed project's competitiveness could be used by the Siting Council to screen out projects which, for example, are priced well above the market rate or are unlikely to receive a power contract in the competitive marketplace due to a lack of maturity (Exh. HO-EPEC-12, p. 12). EPEC also stated that such a determination should not be necessary for projects which have signed and approved power contracts which produce sufficient revenues to allow the project to be financed (id.).

"like kind" projects[69] in terms of cost, reliability, viability, and other factors (id.).

In addition, EPEC provided a comparison of the proposed project to a series of generic alternative technologies (Exh. EPEC-1, pp. II-35 to II-61). EPEC stated, however, that such a project approach analysis "appears to have dubious value," but that it provided such an analysis because it was uncertain whether the requirement for this type of analysis had been eliminated (EPEC Initial Brief, p. III-5).

c. West Lynn Decision

In West Lynn, the Siting Council acknowledged that (1) proposed non-utility projects ideally should be compared to a complete menu of uncommitted resource options available to the state and the region, and (2) such a comparison should be to real resource alternatives which are reasonably likely to be available to satisfy some or all of the identified need within the necessary time frame (EFSC 90-102 at 54). However, the Siting Council also recognized that generally it is not practically possible to compare a proposed project with specific, real alternatives within the scope of a non-utility generating facility review. Id.

In West Lynn, consistent with the MASSPOWER decision, the Siting Council also held that it was no longer appropriate to use technology as the basis for comparing proposed non-utility projects to alternative generic project approaches as part of a

69/ EPEC suggested that "like kind" projects could be grouped on the basis of such factors as fuel type for the purposes of such a comparison (Exh. EPEC-12, p. 3; Tr. 7, pp. 99-101). EPEC stated that the reason for such grouping is that electric utilities should choose a type of project which optimizes its particular supply mix, even if a project from another group might be available at a lower cost (Exh. EPEC-12, p. 3). EPEC asserted that "because least-cost systems require a balanced and diverse resource mix, the lowest cost increment is not always the increment a particular utility should purchase next in order to optimize its least-cost supply plan" (id.).

review of a non-utility facility proposal (EFSC 90-102 at 54).[70] The Siting Council stated that such a comparison failed to evaluate non-utility proposals relative to a full range of resource options and to address whether such proposals were consistent with the resource use and development policies of the Commonwealth. Id. at 53-54.

Nonetheless, the Siting Council stated in West Lynn that it was in no way retreating from its commitment to a project level analysis of non-utility proposals or from its statutory commitment to ensure a least-cost, least-environmental-impact energy supply for the Commonwealth (EFSC 90-102 at 55). Instead, the Siting Council stated that the necessary project level analysis could best be achieved through: (1) reliance on other portions of the Siting Council review; (2) reliance on the newly-developed IRM regulatory framework implemented jointly by the MDPU and the Siting Council; and (3) a renewed emphasis on the resource use and development policies of the Commonwealth. Id.

First, the Siting Council stated that much of its review of non-utility generating facilities, regardless of whether they will provide power to Massachusetts or other regional utilities, comprehensively evaluates the specific cost, environmental and reliability characteristics of proposed projects. Id. The Siting Council noted that its Massachusetts benefits test specifically addresses whether construction and operation of a proposed project within the Commonwealth will provide reliability, economic and/or environmental benefits to the Commonwealth in sufficient magnitude to offset the impacts on the Commonwealth's resources of construction and operation of

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70/ While the Siting Council in West Lynn rejected the generic technology-based comparison as a valid basis for ensuring that our least-cost, least-environmental-impact standard is met, the Siting Council recognized that such a comparison may have some place in discussing how a particular project is consistent with a specific policy of the Commonwealth (EFSC 90-102 at 54).

such a facility (see Section II.A.4, above). Id. In addition, the Siting Council noted that its review of the viability of the proposed project ensures that the project will provide the region with a least-cost and reliable energy resource over the life of its PPAs (see Section II.C, below).[71] Id. Finally, the Siting Council noted that it extensively reviews the cost and environmental impacts of proposed projects in its analysis of proposed facilities (see Section III.D and E, below). Id.

Second, the Siting Council stated that, while utility supply planning in the past often was conducted and regulated via multiple, non-coincident processes at both the MDPU and the Siting Council, the new Integrated Resource Management ("IRM") process for utility supply acquisition will ensure that each affected utility will make resource decisions based on a consistent and comprehensive evaluation of all the resource options available to it.[72] Id. at 56. The Siting Council recognized that the IRM process will provide precisely the appropriate format to conduct the type of comprehensive evaluation of alternative resource options necessary to determine on a utility-by-utility basis which resources represent the least-cost, least-environmental-impact options.[73]

Third, the Siting Council reiterated in West Lynn its decision to now place greater emphasis on determining whether a

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71/ To ensure that a proposed project is viable, the non-utility developer is required to establish that its proposed project offers power below purchasing utilities' avoided costs.

72/ All investor-owned utilities in Massachusetts except the Nantucket Electric Company are subject to IRM. Siting Council's Final Order on IRM Rulemaking, EFSC 90-RM-100A, pp. 8-9 (1990); D.P.U. 89-239 at 47.

73/ IRM may well affect the Siting Council's review in areas separate from project approach. For example, a project that has bid in IRM and is fully subscribed by utilities at the time of its Siting Council filing would not need to demonstrate regional need or Massachusetts benefits. In addition, a fully-subscribed project can address certain elements of the Siting Council's viability standard through its PPAs.

non-utility developer's proposed project is consistent with the resource use and development policies of the Commonwealth. Id. The Siting Council noted in West Lynn that, although we already considered many aspects of a project's consistency with the resource use and development policies of the Commonwealth in our review, we recognized that our review did not provide for an explicit evaluation of a proposed project's consistency with many of the Commonwealth's specific energy, economic and environmental policies (EFSC 90-102 at 56). Therefore, the Siting Council found that it is appropriate to evaluate a proposed project's attributes relative to a broad range of resource use and development policies.[74]

d. Discussion and Analysis

The Siting Council's statutory mandate requires the Siting Council to ensure 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. As discussed in Section II.B.1, above, for non-utility generating facility proposals, the Siting Council traditionally has focused on whether a particular project is the least-cost, least-environmental-impact project when compared to a number of different generating technologies. As indicated in MASSPOWER and further discussed in West Lynn, the Siting Council no longer views this comparative technology approach as effective in ensuring that resource additions proposed for the Commonwealth are necessary, least-cost, and minimize environmental impact. West Lynn, EFSC 90-102 at 53; MASSPOWER, 20 DOMSC at 350-352. The traditional approach of comparing generic technologies (1)

74/ At the time of the West Lynn decision, evidentiary hearings had concluded and briefs had been filed in the EEC and Enron proceedings. In West Lynn, the Siting Council stated that these two cases would be decided based on the record in each case (EFSC 90-102 at 57 n 33). However, the Siting Council noted in that decision that it expected that the reasoning applied in developing the project approach standard in that decision would apply equally in the EEC and EPEC cases. Id.

failed to consider the full range of alternative approaches available to meet a particular identified need, and (2) failed to adequately fulfill the Siting Council's statutory obligation to evaluate projects consistent with the resource use and development policies of the Commonwealth. West Lynn, EFSC 90-102 at 53-54.

In light of the above, we consider EPEC's arguments in this proceeding concerning the project approach standard. EPEC's suggested three-part project approach standard is similar to the revised project approach standard set forth by the Siting Council in the West Lynn decision in some respects. The first part of EPEC's suggested project approach standard appears to conform generally with the standard adopted in West Lynn regarding the consistency of the proposed project with the resource use and development policies of the Commonwealth (EFSC 90-102 at 56-57).

The second part of EPEC's suggested project approach standard, regarding the consistency of the proposed project with various electric utility supply plans, also is somewhat consistent with the Siting Council's recognition that the appropriate forum for deciding among alternate resources is individual utility supply plans. As EPEC indicated, state policy and electric utility least-cost supply plans ideally should be in reasonably close conformance. If they are not, it is highly probable that the Siting Council would reject the utility supply plan in question. Clearly, therefore, a proposed project's consistency with a rejected or outdated electric utility supply plan cannot be accepted as evidence that a project is in compliance with state resource use and development policies.

However, while the Siting Council recognizes that the existence of a recently approved supply plan may be considered evidence that a specific electric utility has a least-cost supply planning process which is generally consistent with state resource use and development policies, an analysis which demonstrates that a proposed project is generally consistent with such a supply plan is simply insufficient to ensure that the proposed project generally is in conformance with the Commonwealth's resource use and development policies. First, individual utility supply plans and the supply planning processes which generate such supply plans are extremely utility-specific. Thus, consistency with such a utility-specific supply plan bears little relevance to the question of overall state policies. Further, without a signed and approved PPA with the specific utility, there is no guarantee that the project will in fact meet those least-cost planning goals.[75]

Recent Siting Council and MDPU decisions on utility supply plans as well as facilities are clearly an important source of guidance on current state energy policy. However, the consistency of a proposed project with the planning criteria set forth in a utility supply plan cannot be considered to be a proxy for consistency with current state resource use and development policies. Therefore, we reject the second part of EPEC's suggested project approach standard here.

The third part of EPEC's suggested project approach standard, regarding a determination that the proposed project is reasonably competitive relative to similar projects, appears to duplicate portions of the Siting Council's present analysis of project viability. As part of our review of project financiability, for example, we require a non-utility developer to establish that its proposed project offers power at a price below purchasing utilities' avoided costs. Therefore, we reject the third part of EPEC's suggested project approach standard here.

In sum, it is our view that it is most appropriate to review a non-utility developer's project in light of a broad range of resource use and development policies. In the following section, the Siting Council reviews the consistency of

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75/ We note that, if a project has a PPA with a utility with a recently approved supply plan, the project would receive credit for this in our analysis of project need.

EPEC's proposed project with the resource use and development policies of the Commonwealth.

2. Consistency with Resource Use and Development Policies of the Commonwealth

In accordance with the standard discussed above, the Siting Council, in this section, assesses the consistency of EPEC's proposed project with the broad resource use and development policies of the Commonwealth. The Siting Council further evaluates the proposed project relative to specific environmental policies in Section III.E, below.

Here, EPEC stated that its proposed project is consistent with the resource use and development policies of the Commonwealth (Exh. EPEC-7, p. 6). Specifically, EPEC asserted that current Massachusetts resource use and development policies are embodied in the IRM regulations developed by the MDPU and the Siting Council (Exh. EPEC-12, p. 11). EPEC further stated that the approach to least-cost integrated planning suggested in the MEOER Report served as the basis for the IRM regulations (Exh. EPEC-7, p. 6). Therefore, EPEC used the MEOER Report as its primary reference in evaluating the consistency of the proposed project with the broad resource use and development policies of the Commonwealth (Exhs. EPEC-7, EPEC-12).

EPEC stated that the MEOER Report identified five criteria for evaluating resource options: (1) feasibility and adequacy; (2) reliability; (3) diversity and flexibility; (4) cost; and (5) environmental, economic and societal impacts (Exh. EPEC-7, p. 7). EPEC asserted that the proposed project would rank highly under each of these criteria (id., p. 8). With regard to the first criterion, EPEC stated that the proposed project is feasible because the facility is financiable given its current level of power sold under long-term contract, and is adequate to meet the region's needs because it is planned to be in operation in time to meet the vast majority of supply and demand contingency conditions (id.; Exh. HO-PV-16). With regard to the second criterion, EPEC asserted that the proposed project is expected to have an annual average availability of 92.5 percent or better (Exh. HO-RR-70). EPEC also asserted that its PPA includes an availability provision designed to penalize the project if it is not available when needed (Exhs. EPEC-2, Appendix B; EPEC-7, p. 8). With regard to the third criterion, EPEC stated that the project would be fired by natural gas, a fuel which it maintains is underrepresented in the region's fuel mix (Exh. EPEC-7, p. 8).[76, 77] In addition, EPEC stated that the use of LNG would increase the diversity of the region's gas supply portfolio (Tr. 2, p. 71). With regard to the fourth criterion, EPEC stated that its project would provide power significantly below the avoided costs of the majority of electric companies in the state (Exh. EPEC-1, pp. II-32 to II-34). With regard to the fifth criterion, EPEC stated the proposed project would produce lower emissions than alternative technologies and would provide significant environmental benefits to the region by displacing the dirtier emissions from older existing facilities along the region's load dispatch curve (Exh. EPEC-7, pp. 8-9).

In addition, EPEC asserted that the proposed project is consistent with the resource plans of a select group of Massachusetts electric companies (id., p. 10). Based on a review of the ComElectric, BECo, and MECo and NEPCo resource plans, EPEC concluded that a gas-fired combined cycle facility such as the proposed project is consistent with the planning criteria of all of these electric companies in terms of cost, reliability, fuel diversity, and environmental impacts (id.).

76/ EPEC stated that natural gas accounted for only 2.0 percent of Massachusetts fuel supply for electricity generation in 1988 compared with 9.5 percent for the United States as a whole (Exh. EPEC-7, p. 8).

77/ EPEC noted that the MEOER Report specifically advocates that Massachusetts diversify its fuel supply mix by increasing the use of natural gas for electric power generation as well as traditional uses (Exh. EPEC-7, p. 9).

EPEC has presented a reasonable set of criteria for evaluating electricity resource options. However, these criteria do not translate directly into broad state policies for resource use and development. While some policies, such as increasing the diversity of the Commonwealth's fuel supplies, tend to remain relatively immutable, others are more dynamic. Clearly, state policies must be flexible in order to be able to adapt to changing external conditions. Moreover, the balancing of tradeoffs among various factors such as economic growth and environmental impact is an important policy question which may change over time. Thus, it is important to focus on up-to-date pronouncements and decisions of relevant state agencies when assessing the consistency of a proposed non-utility generation project with the Commonwealth's public policies rather than relying on fixed evaluation criteria. We note that, in the future, we may request project developers to address the consistency of their projects with specific policies of the state in response to relevant policy issues at that time or in the event that existing policies change or new policies develop.

Nevertheless, EPEC has demonstrated that the proposed project is consistent with Massachusetts' current energy policies in that the use of natural gas as a fuel will help to diversify the Commonwealth's fuel supply mix for electricity generation and thus enhance the reliability and cost stability of the Commonwealth's energy supply.[78] Further, the use of DOMAC LNG as a fuel source for the proposed project adds to the diversity[79] of the region's gas supply portfolio for power

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78/ The Siting Council emphasizes that its finding that the use of natural gas is consistent with the region's fuel diversity policies does not exclude other fuel sources from also being consistent with diversity objectives.

79/ The Siting Council notes that any diversity benefits associated with a particular incremental electrical supply addition must be measured relative to the Commonwealth's existing and planned fuel supply mix at a particular point in time. Thus, in general a second or third LNG-fired electric generation facility would not necessarily convey the same diversity benefits to the region as an initial LNG-fired facility.

generation.[80]

EPEC did not present any information which directly addressed the consistency of the proposed project with the Commonwealth's economic policies. However, EPEC has shown that its project will be able to supply power at a cost which is significantly less than the avoided costs of several of Massachusetts' electric utilities (see Section II.C.2, below). Further, there is nothing in the record to indicate that the proposed project is inconsistent with the Commonwealth's current economic policies. The Siting Council does note, however, that the Commonwealth has clearly stated policies that encourage the development of cogeneration projects. EPEC did not address whether IPPs in general, or the proposed project in particular, are consistent with such policies. The Siting Council further notes that the addition of a limited number of IPPs would not be inconsistent with overall policies related to the development of QFs, but we will expect future proponents of IPPs to address this issue specifically.

The environmental information presented by EPEC indicates that the proposed project is generally consistent with the current environmental policies of the Commonwealth. For example, the record demonstrates that the proposed use of natural gas as a primary fuel would support state policies to minimize air emissions and the potential for other environmental impacts associated with new development including new electrical generation (see Section II.A.4.d, below). See Section III.E, below, for a description of the environmental impacts of the proposed facility at the primary and alternative sites.

80/ EPEC's witness, Mr. Teves indicated that while LNG has a significant role to play in meeting the region's energy needs, the physical capacity and throughput constraints associated with DOMAC's Everett facility, and DOMAC's business decisions regarding the markets it will serve, will act to limit the use of LNG for electricity generation in New England (Tr. 1, pp. 114-118).

In light of the above, EPEC has adequately demonstrated that the proposed project would further a number of broadly representative state policies relating to energy, economic development, and environmental protection.

Accordingly, the Siting Council finds that EPEC has established that the proposed project approach is consistent with the broad resource use and development policies of the Commonwealth.

C. Project Viability

1. Standard of Review

The Siting Council has determined that a proposed non-utility generating project is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned and (2) the project is likely to operate and be a reliable, least-cost source of energy over the life of its power sales agreements. EEC, EFSC 90-100 at 103; West Lynn, EFSC 90-102 at 60; MASSPOWER, 20 DOMSC at 352; Altresco-Pittsfield, 17 DOMSC at 378; NEA, 16 DOMSC at 380.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable and (2) that the project is likely to be constructed within applicable time frames and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements. EEC, EFSC 90-100 at 104; West Lynn, EFSC 90-102 at 61; MASSPOWER, 20 DOMSC at 352; Altresco-Pittsfield, 17 DOMSC at 378.

Here, EPEC asserted that its proposed project meets these tests and therefore would be a viable source of energy over time (EPEC Initial Brief, pp. IV-5 to IV-14). In addition, EPEC offered two suggestions regarding the Siting Council's review of project viability (id., pp. IV-2 to IV-4). First, EPEC argued that local support for a power plant is critical to a project's ultimate viability and should be weighted heavily in the Siting Council's determination of project viability (id., p. IV-2). Second, EPEC argued that much of the Siting Council's review of project viability overlaps with the analysis of project risk required by financial institutions in order to obtain project financing (id.). EPEC asserted that "regulatory efficiencies" could be achieved if the Siting Council were to dispense with "certain parts"[81] of its viability review since the private sector's review of project viability prior to financing would be an adequate substitute (id.).

The Siting Council sees no reason to modify its standard of review of project viability at this time. With regard to EPEC's first suggestion, while the Siting Council acknowledges the importance of public support, as well as public opposition, in the siting of energy facilities, we do not believe that it would be appropriate to make an explicit finding with regard to the degree of such support or opposition in assessing a proposed project's viability. We note that public support for the siting of generating facilities is often based on economic considerations and that public opposition to the siting of such facilities often relates to environmental concerns. Thus, public support or opposition to a proposed facility is often largely unrelated to the specific technical and financial issues which are the subject of our project viability review.

With regard to EPEC's second suggestion, the Siting Council is cognizant of the extensive review of project risk normally required by financial institutions prior to project financing. Nevertheless, we are unwilling to delegate our responsibility for ensuring that a proposed project is viable to an after-the-fact review which is not incorporated into the Siting Council's record. We note that the financial institutions which provide project financing are principally

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81/ EPEC did not explicitly state which specific portions of the Siting Council's review of project viability it believed should be omitted.

concerned with ensuring that an adequate revenue stream will exist to ensure that the terms of the loan can be met, not whether the project will provide a reliable source of least-cost, environmentally acceptable power for the Commonwealth.

Further, while some of the elements considered in our viability review may overlap with portions of a financial institution's evaluation of a project, we recognize that there are a variety of means by which a particular project may assure a potential lender of a guaranteed return on its investment, some of which may have little to do with the specific project characteristics which impact project reliability and cost. In addition, we note that the type and degree of scrutiny to which projects are subjected by potential lenders varies from project to project and is dependent upon the lenders involved as well as the existing financial arrangements of the project being developed.

Finally, we believe that our review of a proposed project's viability provides a useful function for the non-utility power market. A project with Siting Council approval which includes findings related to project viability represents more than "paper project" to potential power purchasers. A Siting Council approval benefits not only the power purchasers and their ratepayers by increasing the likelihood that contracts for power purchases with a NUG will be fulfilled, but also provides an advantage for a NUG with a Siting Council approval in the competitive market for PPAs.

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Council considers whether the project is reasonably likely to be financed so that the project actually will go into service as planned. Here, EPEC indicated that MPLP is responsibile for securing financing for the proposed project (Exh. HO-PV-36).[82]

EPEC asserted that the parent companies -- EPC and Jones Capital -- of the project principals -- EPEC, Jones Charles River, and Jones Medway -- have extensive experience in developing, operating and obtaining financing for major projects, including cogeneration and energy-related projects and commercial and industrial construction projects (Exhs. EPEC-1, pp. I-47 to I-52, HO-B-4, HO-RR-77). In support of this assertion, EPEC stated that EPC is one of the country's largest independent producers of electrical power using natural gas-fired combined cycle and cogeneration technology (Exh. HO-B-4). EPEC noted that EPC had revenues of $176 million and year-end assets of $483 million in 1988 (Exh. EPEC-1, p. I-50). EPEC stated that these assets include ownership interests in four operating cogeneration plants in Texas and New Jersey with an aggregate generating capacity of approximately 1,300 MW (id.; Exh. HO-B-4). EPEC further stated that EPC managed essentially all facets of the development of a 450 MW cogeneration facility in Texas, including financing, and is currently in the process of constructing and finalizing the financing of a 1,725 MW, $1.5 billion gas-fired cogeneration project in England (Exh. HO-B-4; Tr. 7, p. 60).

EPEC also cited the experience of Jones Capital in developing a 50 MW, $100 million cogeneration project in New York, and in managing the development, construction and financing of a variety of other commercial and industrial ventures in the $10 million to $250 million range (Exh. HO-RR-77). In addition, EPEC noted that Jones Capital has access to global sources of debt and equity financing through

82/ EPEC stated that MPLP would seek project financing as an entity; neither the individual partners nor their parent companies would act independently with respect to project financing (Exh. HO-PV-36). EPEC stated that EPC and Jones Capital may participate directly in project financing if lenders require guarantees or other forms of credit support (id.).

its corporate affiliation with Philipp Holzmann AG, a multinational construction firm based in Germany, which in turn is partially owned by Deutsche Bank (id.; Tr. 7, p. 10). EPEC's witness, Mr. Rolfes, indicated that he believed that Jones Capital's association with Deutsche Bank would significantly enhance the project's financiability (Tr. 7, p. 11).

EPEC stated that EPC will fund the permitting and design phase of the project (Exh. HO-PV-4). EPEC further stated that 100 percent construction financing will be obtained from a group of major commercial banks and that, upon completion of construction, project debt would be converted into a long-term "takeout" loan (id.; Tr. 3, p. 129). EPEC stated that the takeout loan would have a term of 15 years, and that it planned to employ a debt-to-equity ratio of approximately 80 percent to 20 percent for long-term financing (Exh. HO-PV-17).[83]

EPEC noted that, as a first step to securing financing for the project, it expects to issue a descriptive memorandum and a set of financial terms and conditions to financial institutions (Exh. HO-PV-4). EPEC stated that it then plans to circulate an RFP to potential lenders and, within approximately six weeks, select a leading lender, negotiate final terms, and execute a loan term sheet with that lender (id.). EPEC estimated that financial closing would take place approximately two months following the execution of a loan term sheet (id.).

EPEC originally stated that it expected to issue its financing memorandum in December 1990 or January 1991, and to complete all financial arrangements by the end of May 1991 (id.). Later, however, Mr. Rolfes testified that EPEC planned to close construction financing in August 1991 (Tr. 7, pp. 37, 40). Mr. Rolfes further stated that, as of March 1991, EPEC had not yet determined a specific group of banks to provide it with financing (id., pp. 60, 61).

83/ Mr. Rolfes stated that EPEC would likely consider a range of debt-to-equity ratios between 70 percent to 30 percent and 90 percent to 10 percent (Tr. 3, p. 129).

EPEC stated that it has been informed by its financial consultant, Goldman, Sachs & Company ("Goldman Sachs"), that the proposed project is financiable based on its present PPA in combination with short- to medium-term sales of the remainder of the plant's capacity and/or energy (Exhs. HO-PV-16, HO-RR-46; Tr. 7, p. 59).[84] In support of this statement, EPEC provided a letter from Goldman Sachs, dated August 6, 1990 (Exh. HO-PV-16). EPEC indicated, however, that it would not expect to obtain the lowest available interest rates, and may be required to create a debt service reserve fund, if the proposed project did not sell a higher percentage of its capacity (id.; Tr. 3, pp. 121, 122). EPEC stated that if it were unable to secure commitments for additional capacity by the time of project financing, EPEC would include provisions in its loan documents which would allow for refinancing at better interest rates and the elimination of any debt reserve funds once such commitments were obtained (id.).

Mr. Rolfes testified that debt coverage ratio ("DCR") is a standard index used by financial institutions to assess a project's ability to repay its debt (Tr. 3, p. 136).[85] Mr. Rolfes stated that financial institutions typically look for an average annual DCR of about 1.5 (id.). Mr. Rolfes further stated that projects with an average DCR between 1.0 and 1.5 are financiable, but as a project's DCR approaches 1.0, lending institutions are increasingly likely to require debt coverage reserves and other guarantees (id., pp. 136, 137). Mr. Rolfes indicated that a project with a DCR between 1.35 and 1.5 could be financed readily, but might require the establishment of a debt coverage reserve (Exh. HO-RR-46; Tr. 3, p. 137).

84/ EPEC currently has a PPA for 82.53 MW (57.2 percent of the project's capacity) with NEPCo (Exh. EPEC-1, p. I-40). See Section II.A.2, above, for a further discussion of EPEC's PPA status.

85/ Debt coverage ratio equals project income minus expenses divided by required debt payments over a given period of time (Tr. 3, p. 136).

EPEC provided pro forma financial analyses for its project under scenarios involving different levels of capacity and energy prices that EPEC expected it could obtain for unsold power, plant availability, natural gas and gas transportation prices, choice of cooling tower technology, and debt-to-equity ratios (Exhs. HO-PV-18, HO-RR-43, HO-RR-46A, HO-RR-47).[86] In its base case, EPEC assumed an 80 percent to 20 percent debt-to-equity ratio and that the project's unsold power would be sold at the same capacity and energy rates included in EPEC's PPA with NEPCo (Exhs. EPEC-2, Appendix B, HO-PV-18, HO-RR-46). Under this set of assumptions, EPEC projects an average DCR of 1.74 over the 15-year term of the loan (Exhs. HO-PV-18, HO-RR-46).[87]

In addition, EPEC asserted that, based on sensitivity analyses of its financial pro formas, the proposed project would produce, over a broad range of scenarios, DCRs which would meet the typical requirements of financial institutions (Exh. HO-RR-46). In particular, EPEC argued that the proposed project would be financially viable given a range of realistic assumptions regarding the short-term sales revenues that it would be likely to receive for the unsold 43 percent of the project should EPEC fail to obtain additional commitments for long-term power sales agreements prior to financing (Exhs. HO-PV-18, HO-RR-48; EPEC Initial Brief, pp. IV-10 to IV-12). EPEC further argued that its analyses demonstrated that, by lowering its debt-to-equity ratio from 80 percent to 20 percent to 70 percent to 30 percent, or, if necessary, to

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86/ Mr. Rolfes stated that EPEC did not believe it was necessary to prepare pro forma sensitivity analyses of capital costs and interest rates because these costs were known with a high degree of certainty (Tr. 3, pp. 125-128).

87/ EPEC also stated that, because the proposed project is being financed over a 15-year loan term, EPEC's DCRs are likely to be lower than the DCRs of projects such as MASSPOWER which are being financed over a 20-year period (Exh. HO-RR-46; EPEC Initial Brief, pp. IV-8) See MASSPOWER, 20 DOMSC at 353-356.

60 percent to 40 percent, the proposed project would be able to achieve average DCR's of 1.33 or above under a variety of realistic assumptions regarding the revenues from the unsold portion of the project (EPEC Initial Brief, p. IV-11).

EPEC further argued that the proposed project's availability would be more than adequate to assure the project's financiability (Exh. HO-PV-18; Tr. 3, pp. 126-127). EPEC stated that the project must achieve a minimum average availability level of at least 79 percent in order to maintain a positive cash flow and hence a DCR greater than 1.0 (id.). EPEC stated that the project's actual availability is expected to be 92.5 percent or better, citing similar availability levels for EPC's four other gas-fired power plants currently in operation (Exh. HO-RR-70; Tr. 3, pp. 126-127).[88]

EPEC asserted that its proposed project is "extremely competitive" in the current market for power (EPEC Initial Brief, p. III-22). In support of this assertion, EPEC performed: (1) a comparison of the cumulative net present value of the cost of power from the proposed project, based on the pricing terms of the NEPCo PPA, and the avoided costs of several electric companies in Massachusetts, which indicated that the proposed project is below the avoided costs of each of these utilities (Exhs. EPEC-1, p. II-32 to II-34, EPEC-2, Appendix B, HO-PV-18); (2) a comparison of the real levelized cost of power

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88/ EPEC indicated that disruptions in the plant's fuel supply are likely to be rare and short-lived, and, therefore, would have a minimal impact on the project's average availability over the term of the PPAs (Exh. HO-PV-28). The Siting Council analyzes the reliability of the project's fuel supply in Section II.C.3.b, below. EPEC also stated that it would not utilize MWTP wastewater effluent during periods when the flow of the Charles River falls below 3 cubic feet per second in order to reduce the impact of the project on the Charles River (Exh. EPEC-19, pp. 5-1 to 5-6). EPEC stated that this water mitigation plan would not reduce the plant's availability due to the availability of on-site water storage and potable water supplies from the MWC (Exh. HO-RR-70). The Siting Council analyzes the impact of this plan on the reliability of the project in Section III.F, below.

of the EPEC project (4.86 cents per kwh) with the real levelized cost of projects which have recently signed PPAs, which EPEC asserted showed that the proposed project "compares very favorably to the cost of other projects which have power contracts" (Exh. EPEC-12, pp. 18, 19); and (3) a comparison of the real levelized cost of power of the EPEC project with the real levelized cost of projects which ranked highly in the most recent BECo QF solicitation, which EPEC stated showed that "on a price basis alone, the EPEC project would have been in or very close to the award group" (id., p. 19).

In addition, EPEC stated that, in the event that it is unable to obtain conventional construction financing by the August 20, 1991 milestone date specified in its NEPCo PPA, it would be able and willing to finance the project with internal funds in order to meet the schedule set forth in the NEPCo PPA (Exhs. EPEC-1, p. I-48, EPEC-2, Appendix B, HO-N-8). In support of this statement, Mr. Rolfes testified that EPC is currently financing the start of construction of its $1.5 billion cogeneration project in England while it is in the process of closing on conventional financing (Tr. 7, p. 60). Mr. Rolfes stated that he believed that Jones Capital also would be willing to self-finance its share of the EPEC project in the event of a delay in conventional financing (id.).

The Siting Council notes that because 57 percent of the proposed project's power is already sold under a long-term contract, EPEC is in a favorable position to obtain project financing. EPEC has presented a number of scenarios which address the sensitivity of project finances to important variables such as plant availability and the price of unsold power. The range of assumptions provided by EPEC, including EPEC's set of base case assumptions, is generally reasonable. The results of these sensitivity analyses indicate that the EPEC project is financiable based on projections of DCRs across a broad array of scenarios.

In addition, EPEC's pro formas indicate that EPEC would be able to offer its power below utilities' avoided cost; hence

EPEC should be able to sign additional long-term PPAs in the near future. Even in the absence of additional long-term PPAs, EPEC has shown that the proposed project is financiable with its existing NEPCo contract in combination with short-term sales contracts using realistic price projections.

Further, EPEC's analyses of plant availability indicate that the plant is financiable given expectations regarding the frequency and duration of disruptions in fuel supply and MWTP wastewater effluent. While such disruptions could potentially have some effect on the proposed project's availability in a given year, the average impact of such potential disruptions over the term of the NEPCo PPA should be relatively small.

In sum, EPEC's analyses of the proposed project's DCR provide significant evidence regarding the financiability of the project. In addition, EPC's and Jones Capital's experience and financial strength, together with their stated willingness to finance the construction of the proposed project using internal funds if necessary, provides a significant additional measure of confidence that the project will be financed. Moreover, EPEC's avoided cost comparisons and its establishment of a need for the project based on reliability and economic efficiency grounds (see Sections II.A.3.b and c, above) indicate that the output of the proposed project is likely to be contracted for in a manner that can support project financing.

Based on the foregoing, the Siting Council finds that EPEC has established that its proposed project is likely to be financed.

b. Construction

In considering a proponent's construction strategy for a proposed project, the Siting Council considers whether a project is reasonably likely to be constructed so that the project would actually go into service as planned. Here, EPEC provided an executed contract between MPLP and Enron Milford Construction Company ("EMCC"), dated August 14, 1991, to provide engineering and construction ("E&C") services for the proposed project

(Exh. HO-PV-33(5) (Sup. 3)).[89] EPEC estimated that construction of the proposed project would require about 19 months from the date of closing of construction financing (Exh. HO-RR-81).

EPEC stated that EPC would serve as general contractor for the construction of the project (Exh. EPEC-1, pp. I-38, I-39). As such, EPC will be responsible for providing specified equipment, engineering and labor to construct the proposed project and to supervise start-up and testing (Exh. HO-RR-81). EPEC stated that EPC will enter into subcontracts for the three primary project components -- engineering and design, equipment purchase and construction -- while maintaining overall management of the project, including the construction schedule and budget (Exh. EPEC-1, pp. I-38, I-39).

The E&C contract contains a set of binding terms and conditions for the engineering and construction of the proposed project, including terms to assure the timeliness and quality of construction (Exh. HO-PV-33(5) (Sup. 3)). For example, the E&C contract includes various incentive provisions such as bonus and penalty terms for early and late completion and for power plant heat rate and net output (id.).

The E&C contract sets forth the respective responsibilities of MPLP and EMCC for designing and constructing the proposed facility, the guaranteed completion date for the project, the performance tests which EMCC is to carry out following the completion of construction, a set of bonus/penalty provisions for early/late completion of construction and for plant heat rate and net output, a guaranteed emissions rate, and a series of other provisions (id.). The E&C contract also includes a fixed construction contract price, subject to adjustment under certain conditions (id.).

89/ EPEC stated that EMCC is the project subsidiary through which EPEC's corporate parent, EPC, would construct the proposed project (Exh. HO-PV-33(5) (Sup. 2)). EPEC asserted that the experience and qualifications of EPC would be directly applied to the proposed project through EMCC (id.).

EPEC asserted that EPC has a strong track record in all areas of power plant project development, including design and construction (Exh. EPEC-1, pp. I-23 to I-25). EPEC cited EPC's experience in successfully controlling costs and project schedules by serving as its own general contractor and manager, emphasizing that it completed the construction of two large cogeneration plants in Texas and New Jersey before schedule and under budget (id., pp. I-38, I-39).

In terms of its facility site and access arrangements, EPEC provided a copy of a signed site purchase and sale agreement, dated March 9, 1991, with Fafard Realty, the owner of the primary site (Exh. EPEC-2, Appendix B). EPEC stated that this purchase and sale agreement allows EPEC to acquire this site at any time prior to February 1, 1993 (id., Exh. EPEC-1, p. I-30). EPEC further stated that this agreement was amended on April 8, 1991 to provide EPEC with the right to acquire the northern section of the primary site, consisting of 2.4 acres and including the existing warehouse building on that property, in addition to the original 4.4-acre site (Exh. HO-RR-82). EPEC also stated that a purchase and sale agreement for a parcel of land located adjacent to the primary site ("Lot 2") was signed on March 22, 1991, and that EPEC has the right to take title to that property at any time prior to November 30, 1991 (Exhs. HO-PV-37, HO-RR-82). EPEC provided executed copies of both the April 8, 1991 revised purchase and sale agreement for the primary site and the March 22, 1991 purchase and sale agreement for Lot 2 (Exh. HO-PV-37).

EPEC also provided a signed agreement with the Town of Milford, dated July 31, 1991, ensuring EPEC access to wastewater effluent from the MWTP for water supply purposes (Exh. HO-PV-33(3) (Sup.)). This wastewater effluent agreement is for a term of five years, with a provision to extend the agreement by an additional 25 years (id.).[90] The wastewater effluent agreement sets forth the price schedule for the purchase of the wastewater effluent, minimum water quality standards for wastewater effluent and influent, the maximum quantity of effluent which EPEC may use, and other relevant information (id.). In addition, the wastewater effluent agreement guarantees that EPEC would not be displaced by any other potential users of the wastewater effluent (id.).

With regard to electrical interconnection arrangements, EPEC provided a copy of a transmission interconnection study performed by NEPCo (Exh. HO-RR-79). EPEC indicated that it is discussing a draft interconnection agreement with NEPCo, but it has not yet executed such an agreement (Exh. HO-PV-33(8) (Sup. 1)). Nevertheless, EPEC argued that its interconnection arrangements are "well advanced" and thus at a similar stage to the interconnection arrangements accepted by the Siting Council in the EEC decision (id.). See EEC, EFSC 90-100 at 110. EPEC stated that it would construct two parallel transmission lines, each approximately 1,000 feet in length, to connect the proposed project with the local NEPCo transmission system (Exh. EPEC-19, p. II-19). In addition, EPEC initially indicated that it would be necessary to upgrade the local electrical distribution network in Milford by accelerating the installation of a new substation in Milford from June 1, 1997 to January 1, 1993 in order to handle the additional loading on the existing substation transformers located on Depot Street in Milford

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90/ According to the wastewater effluent agreement, the Milford Sewer Commission will sponsor an Article at the next special Town Meeting of the Town of Milford to extend the length of the wastewater effluent agreement by 25 years to a total length of 30 years (HO-PV-33(3) (Sup.)). The wastewater effluent agreement further provides that should the Town meeting not approve such an extension, the agreement may be extended for up to five additional, five-year terms by vote of the Milford Sewer Commission (id.).

(Exhs. HO-RR-79, HO-RR-94).[91, 92]

However, on August 6, 1991, EPEC notified the Siting Council that it had developed an alternative interconnection design strategy, which it referred to as a "Special Protection Scheme" ("SPS") (Exh. HO-PV-33(8) (Sup. 1)). EPEC stated that the SPS would allow the proposed project to interconnect with the NEPCo transmission system without the construction of the new substation until NEPCo's originally planned date in 1997 (id.). However, EPEC provided almost no information describing the SPS or justifying its use. EPEC stated that a draft interconnection agreement has been prepared based on the use of the SPS and expects to finalize an interconnection agreement which includes the SPS (id.).

In a letter from NEPCo to EPC dated July 19, 1991, NEPCo noted that the SPS would remove EPEC's generation from NEPCo's system during Depot Street transformer overloading conditions (id.). EPEC did not provide any information regarding the frequency, duration, or timing of such transformer overload conditions. In this letter, NEPCo stated that its original position was that an SPS was not acceptable as long as other solutions were available (id.). NEPCo further stated that, at EPC's request, it has reconsidered the use of an SPS (id.).

91/ The NEPCo interconnection study concluded that the effect of bringing the proposed project on-line would be "to cause contingency flows in the Depot Street transformers which exceed their emergency capabilities," and, therefore, that the construction of a new substation "must be advanced to the operational date of the Enron generation" (Exh. HO-RR-79, pp. 7-8). NEPCo indicated that such contingency overloading of the Depot Street substation transformers would be unacceptable (Exh. HO-PV-33(8) (Sup. 1)).

92/ EPEC stated that, if it were to pursue this arrangement, it would pay NEPCo for the costs to construct the new substation, and then it would be entitled to a future reimbursement from NEPCo for the substation costs since the substation would be required eventually for area load growth even if the proposed project is not built (Exh. HO-PV-33(8) (Sup. 1)). The estimated cost of the new substation is $1.975 million (Exh. HO-RR-79, pp. 1-2).

NEPCo indicated that it now acknowledges that, while the SPS would not be its preferred option, in this particular case an SPS could possibly be designed to adequately address its concerns, and that it is willing to work with EPC to develop a mutually acceptable design (id.). However, NEPCo also states that "by design, an SPS will remove Enron's generation from [NEPCo's] system upon the occurrence of unacceptable conditions, and these conditions may occur suddenly, without advanced warning. Enron must accept all of the consequences of this action." (id.).

In the past, the Siting Council has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is likely to be constructed on schedule and will be able to perform as expected. Altresco-Pittsfield, 17 DOMSC at 380. Here, EPEC has submitted a signed E&C contract. The E&C contract includes a number of advantageous provisions, including a fixed price provision which will inherently mitigate financial risk to MPLP and bonus/penalty provisions which will help to ensure the timeliness and quality of construction.

In addition the record indicates that EPC has a great deal of experience in various facets of power plant development, including design and construction. Moreover, EPEC has submitted a signed purchase and sale agreement for the primary site.

A wastewater effluent purchase agreement between MPLP and the Town of Milford also has been executed. The wastewater effluent agreement provides significant revenues to the Town of Milford and ensures that the proposed project will have access to an adequate supply of water for cooling purposes during periods when streamflow in the upper Charles River is above three cubic feet per second ("cfs"). See Section III.E.2, below, for more information on the availability of water supply.

With respect to EPEC's interconnection arrangements, the Siting Council notes that, just two weeks prior to the date of this tentative decision, EPEC informed the Siting Council that it had changed its interconnection strategy and now plans to rely on an SPS which would allow it to interconnect with the NEPCo transmission system. However, EPEC provided essentially no information explaining what the SPS would be, how it would work, how much money it would save relative to accelerating the construction of the planned new substation, or, most importantly, what the implications of employing the SPS are for the reliability of the proposed project's power output. Further, EPEC did not provide any information regarding the cost savings that it would realize by implementing the SPS nor any documentation that such cost savings in fact would occur.

The Siting Council is greatly concerned with the potential adverse effects of the SPS on the reliability of the proposed project. The SPS apparently would require the EPEC project to shut down during periods when the existing Milford Street transformer is overloaded. EPEC has provided no information regarding the frequency, duration, or timing of such shutdowns. The interconnection study performed by NEPCo indicates that bringing the proposed project on-line would, without the construction of a new substation, cause contingency flows in the Depot Street transformers which exceed their emergency capabilities. NEPCo itself warned EPC that "it must face all of the consequences" of employing an SPS. The limited information regarding the SPS provided by EPEC does not provide the Siting Council with confidence that the proposed project would be able to operate as a reliable source of power if such an interconnection plan were to be employed.

EPEC's argument that its interconnection arrangements are well advanced may be true in terms of the status of negotiations with NEPCo. Nevertheless, an interconnection arrangement which does not permit a proposed project to operate in a reliable manner has significant adverse implications for project viability, and is simply unacceptable to the Siting Council. Here, we lack adequate information to determine the impact of EPEC's SPS on project reliability.

EPEC has failed to establish that its planned interconnection arrangements involving the use of an SPS would allow the proposed project to operate in a reliable manner. The Siting Council recognizes that EPEC may be able to provide sufficient documentation to establish that its planned interconnection arrangements involving the use of an SPS would allow the proposed project to operate in a reliable manner. However, the record indicates that EPEC's original plan to pay for the acceleration of construction of a new substation in the Milford area would be an acceptable interconnection arrangement which would allow the proposed project to operate as a reliable source of energy over the course of its PPA.

Accordingly, the Siting Council ORDERS EPEC to (1) implement its initial interconnection plan involving the construction of a new substation in the Milford area, or alternatively, (2) provide the Siting Council with sufficient documentation demonstrating that the proposed project would be able to operate as a reliable source of energy under the SPS over the course of its PPA.[93]

Accordingly, based on compliance with the above ORDER, the Siting Council finds that EPEC has established that its proposed project is likely to be constructed within applicable time frames and to be capable of meeting performance objectives.

The Siting Council has found that EPEC has established that its proposed project (1) is likely to be financed, and (2) upon compliance with the above ORDER, is likely to be constructed within applicable time frames and to be capable of meeting performance objectives. Accordingly, upon compliance with the above ORDER, the Siting Council finds that EPEC has

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93/ In the event that EPEC chooses to pursue its SPS plan and provides the Siting Council with documentation regarding that plan, and should the Siting Council determine that EPEC has failed to demonstrate adequately that, under the SPS plan, the proposed project would be able to operate as a reliable source of energy over the course of its PPA, EPEC would be required under this ORDER to implement its initial interconnection plan involving the construction of a new substation in the Milford area. Further, operation of the proposed project may not commence until such substation is operational.

established that its proposed project meets the Siting Council's first test of viability.

3. Operations and Fuel Acquisition

a. Operations

In determining whether a proposed non-utility generation project is likely to be viable as a reliable, least-cost source of energy over the life of its power sales agreements, the Siting Council evaluates the ability of the project proponent or other responsible entities to operate and maintain the facility in a manner which ensures a reliable energy supply. EEC, EFSC 90-100 at 111-112; West Lynn, EFSC 90-102 at 67; MASSPOWER, 20 DOMSC at 359; Altresco-Pittsfield, 17 DOMSC at 381. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent must establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks should be set out pursuant to detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. West Lynn, EFSC 90-102 at 67; MASSPOWER, 20 DOMSC at 359; Altresco-Pittsfield, 17 DOMSC at 381-382.

Here, EPEC stated that its corporate parent, EPC, would be responsible for operating and maintaining the proposed project (Exh. EPEC-1, pp. I-39, I-40). EPEC provided an executed operation and maintenance ("O&M") agreement, dated August 1, 1991, between MPLP and EPC ("original O&M agreement") (Exh. HO-PV-33(6) (Sup. 3)). EPEC stated that EPC has extensive experience in the operation and maintenance of power plants, including several large cogeneration facilities in Texas and New Jersey (Exh. EPEC-1, pp. I-23 to I-27). The original O&M agreement provided by EPEC sets forth the respective responsibilities of MPLP and EPC for operating and maintaining the proposed project, the base compensation level which EPC is to receive for its services, and a set of bonus/penalty provisions based on plant heat rate and capacity factor (Exh. HO-PV-33(6) (Sup. 3)). The original O&M agreement is for a term of 15 years, with a provision for renewal for successive five year terms (id.).

The original O&M agreement also included a provision which provided that that agreement would be terminated automatically on the date upon which the proposed project would become an 'electric utility company' within the meaning of the Public Utility Holding Company Act of 1935, as amended ("PUHCA") (id.). EPEC stated that EPC would seek to assign the O&M agreement to an independent vendor at some time prior to the commencement of plant operation, when the jurisdiction of PUHCA would be triggered, in order to avoid PUHCA regulation of its affiliated partners (id., (Sup. 1)).

On August 23, 1991, EPEC provided an executed amendment to the original O&M agreement (id., (Sup. 3A)). The executed amendment deleted from the original O&M agreement all provisions which would have (1) permitted the O&M agreement to be terminated on the date which the project would become subject to PUHCA, or (2) permitted MPLP to assign that agreement to an unaffiliated third party prior to the start-up and testing of the proposed project (id.). EPEC also provided a letter from the chairman of EPC, dated August 26, 1991, stating that EPC is committed to provide O&M services to the proposed project, and, if necessary, would reduce its affiliated ownership or take other action to allow it to provide such O&M services without subjecting its affiliates to regulation under PUHCA (id., (Sup. 3B)).

In a previous case, the Siting Council found that an executed O&M contract assured the Siting Council that a project is likely to be operated and maintained in a manner consistent with reliable performance over the life of its power sales agreements. Altresco-Pittsfield, 17 DOMSC at 382. Here, EPEC has provided an executed O&M agreement, complete with appropriate bonus and penalty provisions, with EPC, a qualified vendor. Further, EPEC has amended the original O&M agreement in a manner which ensures that (1) the contract is legally binding, and (2) EPC will actually be responsible for performing the O&M services for the proposed project. Moreover, the amended O&M agreement contains sufficient detail to assure the Siting Council that the project is likely to be operated and maintained in a manner consistent with reliable performance over its expected life.

Accordingly, the Siting Council finds that EPEC has established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

b. Fuel Acquisition

In considering an applicant's fuel acquisition strategy, the Siting Council considers whether such a strategy reasonably ensures low-cost, reliable energy resources over the terms of the proposed project's PPAs.

EPEC provided a copy of an executed 15-year contract with DOMAC for approximately 28,900 million British Thermal Units per day of natural gas on a firm basis for 365 days per year (Exhs. EPEC-1, p. I-47, EPEC-2, Appendix F; HO-PV-28, p. 1, HO-PV-34). EPEC indicated that DOMAC would provide the total fuel requirements of the proposed project with LNG (Exh. EPEC-1, p. I-47). The gas supply contract requires DOMAC to reimburse EPEC for the cost of alternative fuel supplies should DOMAC fail to provide the contracted for gas supplies except in the case of force majeure events (Exh. HO-PV-28, p. 1).

EPEC stated that the project's gas supplies would be transported from DOMAC's existing LNG terminal in Everett, Massachusetts, to the vicinity of the site of the proposed project via backhaul on the Algonquin pipeline (Tr. 1, pp. 77, 78). In order to accomplish this transportation, EPEC indicated that Algonquin would need to loop its existing pipeline in the Milford area for a distance of approximately 3.1 miles (Exhs. EPEC-1, pp. I-36, I-37, HO-PV-34). EPEC stated that an application to perform this looping on the Algonquin system was filed with the FERC on May 13, 1991 (Exh. HO-PV-34). EPEC estimated that FERC would issue a decision in the proceeding in April 1992 (id.). EPEC stated that it did not anticipate any difficulties in securing timely FERC approval of the project (Tr. 7, pp. 28-30).[94]

EPEC indicated that Commonwealth Gas Company ("ComGas"), a local distribution company ("LDC") which serves the Milford area, would be responsible for transporting these gas supplies a distance of approximately 200 feet from the Algonquin pipeline to the proposed project (Exhs. EPEC-1, pp. I-36, I-37, HO-PV-33(1)). EPEC stated that it would construct the required 200-foot long gas interconnection line, and then transfer ownership of that line to ComGas (Exh. HO-PV-33(1)). EPEC indicated that it is currently negotiating an agreement with ComGas to operate the 200-foot gas interconnection line and expects to execute an agreement with ComGas by August 31, 1991 (id.; Exhs. HO-PV-33(1) (Sup. 2), HO-RR-81).[95]

EPEC stated that the price of its DOMAC gas supply is composed of two parts (1) a "monthly call payment" or demand charge which reflects the fixed costs of transporting competitive natural gas supplies to New England via pipeline, and (2) a commodity component which reflects the costs of purchasing competitive fuel supplies (Exhs. HO-C-2, HO-C-7). EPEC explained that the demand charge would escalate in line with competitive gas pipeline transportation sources in

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94/ EPEC stated that it expected that construction financing could be closed without FERC approval of the Algonquin looping project because potential lenders would recognize "that this is a fairly routine FERC action for looping" (Tr. 7, pp. 29, 30, 79-80).

95/ EPEC stated that, should it be unable to reach an agreement with ComGas prior to the scheduled start up of project construction, it plans to begin construction and continue to negotiate with ComGas (Exh. HO-PV-33). EPEC further stated that, if necessary, it would preserve its rights under MDPU regulations to request a regulatory review and determination of the appropriate provisions which should be contained in the ComGas transportation agreement (id.).

New England, and that the commodity charge would escalate at the rate of NEPOOL's average fossil fuel index ("AFFI") (id.).

EPEC asserted that indexing the commodity cost of its gas supply to NEPOOL's average cost of fossil fuel would ensure stability in the price of its fuel supply because of NEPOOL's diverse supply mix (Exh. HO-C-2). EPEC further asserted that the use of the AFFI would act to restrain the level of potential price escalation because utilities would naturally tend to shift to using more of lower cost fuels over time (Exh. HO-C-7). EPEC also stated that its fuel supply contract ensures that the proposed project would achieve a dispatch level of at least 80 percent over the term of its PPA through the inclusion of a low initial price and a provision which allows prices to be adjusted periodically to ensure such a dispatch level (Exh. HO-C-2). EPEC argued that because the cost of fuel is a major component of the total cost of a gas-fired combined cycle facility, the terms of its gas supply contract, including its low initial cost, would ensure that the proposed project can price its power at or below the prices for comparable power (id.; Exh. EPEC-1, p. I-21).

Mr. Teves stated that DOMAC has adequate storage and vaporization capacity at its Everett facility to provide its full supply commitments to the proposed project in addition to its other supply commitments (Exhs. HO-PV-23, HO-PV-27). Mr. Teves also noted that DOMAC does not oversubscribe its LNG sales and storage capacity (Tr. 1, pp. 49, 63, 101). Rather, Mr. Teves explained, when DOMAC signs a supply contract, it removes the committed supplies under that contract from its long-term marketing program (id., p. 63).[96] Mr. Teves stated

96/ Mr. Teves stated that DOMAC has a limited willingness and ability to serve the power generation market (Tr. 1, pp. 114-118). Mr. Teves indicated that DOMAC's goal was to split its sales evenly between the power generation and traditional gas utility markets, and that therefore, DOMAC would be unable to serve more than a small number of large power plants with firm year-round gas supplies (id.). Mr. Teves further indicated that the potential demand for LNG in the power (footnote continued) that DOMAC currently obtains all of its LNG from Algeria via ocean tanker (id., p. 60). DOMAC currently is negotiating with its Algerian supplier, Sonatrach, to extend its current long-term LNG contract, which is due to expire in 2003, to 2008 (Exh. HO-RR-1; Tr.1, pp. 61-65).[97]

Mr. Teves asserted that DOMAC LNG supplies are a reliable source of energy (Tr. 1, pp. 34-36, 64). In support of this assertion, Mr. Teves cited: (1) DOMAC's long track record of delivering firm LNG supplies to the region in a reliable manner;[98] (2) the record of Sonatrach, DOMAC's Algerian supplier, in living up to contract terms for a period of more than 20 years; (3) Algeria's extensive reserves of natural gas; (4) DOMAC's long term commitment to the LNG trade as reflected in the recent acquisition of an LNG tanker, the considerable investment required to resolve DOMAC's take-or-pay difficulties, and DOMAC's planned investments in the Everett facility; and (5) DOMAC's aforementioned efforts to diversify its supply

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(footnote continued) generation market exceeds DOMAC's supply capabilities, and, as a result, DOMAC employs a detailed screening process to select which projects it will supply (Exh. HO-RR-2; Tr. 1, pp. 98-99). Mr. Teves noted that the proposed EPEC project ranked highly in this screening process (Tr. 1, pp. 96-99).

97/ DOMAC also indicated that it likely would continue to receive LNG shipments under its current contract for several years beyond the official expiration date of its contract with Sonatrach even if that contract were not to be successfully renegotiated because it likely would not transport the entire volume of gas committed to DOMAC under the current contract prior to 2003 (Tr. 1, pp. 55, 61).

98/ Mr. Teves indicated that DOMAC has been supplying LNG to the New England region for over 20 years and sells LNG on a firm or interruptible basis to over 25 gas utilities, electric power plants and cogeneration facilities (Exh. HO-PV-6, Tr. 1, pp. 30-31). Mr. Teves stated that DOMAC presently provides approximately 12 percent of the region's natural gas supplies (Tr. 1, pp. 30, 31).

sources (id.).[99] Mr. Teves acknowledged that the logistics of the production, transportation and vaporization of LNG involves a more complex chain of events than the logistics of moving pipeline gas to markets (id., p. 67). Mr. Teves asserted, however, that each of the links in LNG's logistical chain has proven to be highly reliable, and that LNG is as reliable a source of energy as pipeline gas (id., pp. 67-69).[100, 101]

EPEC acknowledged the possibility of disruption in its

99/ Mr. Teves also noted that an affiliate of DOMAC is currently negotiating a long-term supply contract with Nigeria in order to diversify its sources of supply (Exh. HO-PV-28, p. 7; Tr. 1, pp. 43-45). EPEC asserted that the addition of new producers such as Nigeria, Venezuela, Norway and Trinidad will enhance the reliability and flexibility of LNG trade in the Atlantic Basin in the future (Exh. HO-PV-28, p. 8; Tr. 1, p. 52). Mr. Teves indicated that the Nigerian supplies are (footnote continued) expected to be available as early as 1995 (Tr. 1, p. 35). Mr. Teves also stated that gas supplies for the proposed EPEC project would be provided under DOMAC's existing long-term contract with its Algerian supplier and thus were in no way dependent on the outcome of DOMAC's negotiations with Nigeria (id., pp. 48-49).

100/ EPEC also asserted that DOMAC LNG supplies are reliable, citing (1) a September 16, 1988 U.S. Department of Energy ("DOE") decision (DOE/ERA Opinion and Order No. 271, p. 6) approving DOMAC's importation of LNG in which DOE stated that DOMAC's "import arrangement provides a reliable and secure source of supply," and (2) a December 16, 1988 FERC decision (Docket No. CP88-587-000) in which FERC cited the "high reliability of supply existing under the proposed individual contracts" in approving the restructuring of DOMAC's services (Exh. HO-PV-9).

101/ Mr. Teves acknowledged that DOMAC had experienced some disruptions in supply during its existence (Tr. 1, pp. 32-33). Specifically, Mr. Teves noted the following episodes: (1) in the early 1970's DOMAC experienced a delay in the startup of its operation when the construction of LNG facilities in Algeria was delayed; (2) in the winter of 1980/81, LNG deliveries were delayed for two weeks by a severe storm in the loading port in Algeria; and (3) in 1988, DOMAC sought temporary protection under the U.S. bankruptcy code in order to gain relief from take-or-pay obligations (Exhs. HO-PV-6, HO-PV-28, p. 6; Tr. 1, pp. 32-34, 38). Mr. Teves stated that DOMAC's take-or-pay problems have since been fully resolved (Tr. 1, p. 34).

DOMAC supplies (Exhs. HO-PV-9; HO-PV-28). Specifically, EPEC stated that equipment failure or transportation problems could result in short-term supply availability problems, and that a cutoff in supplies from Algeria could result in a supply shortfall of a longer duration (Exh. HO-PV-28, p. 6). EPEC asserted, however, that any such disruptions are likely to be rare and of relatively short duration (Exh. HO-PV-9; Tr. 1, pp. 32-35). EPEC further stated that disruptions are possible in any fuel supply, and that "with the contractual damage provisions of the gas purchase agreement and the combined abilities of DOMAC and EPEC to find alternative sources of LNG, EPEC considers the risk of disruption to be at an acceptable level for project financing" (id.; Exh. HO-PV-28). EPEC further asserted that Enron's position as a major international energy producer and as the operator of a large domestic pipeline system places EPEC in a unique position to secure gas supplies and transportation from a wide variety of sources if necessary (Exh. HO-PV-28).

When questioned regarding NEPCo's attitude toward the reliability of LNG as a supply source, Mr. Hachey stated that there was a great deal of potential to diversify supply sources within the natural gas market, either on pipelines or with LNG, and that, in this instance, NEPCo saw the use of LNG as contributing to the diversity of its supply sources (Tr. 2, p. 71). Mr. Hachey contrasted the current availability of LNG as a supply source favorably with the uncertainties associated with the construction of proposed new pipelines (id., pp. 70-73). Mr. Hachey further stated that NEPCo attempts to balance the risks associated with various supply sources as it plans the expansion of its overall supply portfolio (id., p. 72).

EPEC also provided a fuel supply contingency plan (Exh. HO-PV-28). In this plan, EPEC described four gas supply and transportation options available to EPEC should DOMAC fail to meet the gas supply conditions of its contract with EPEC (id., p. 6). These options are as follows: (1) replace the Algerian supply with LNG from another source; (2) purchase gas from a LDC such as Boston Gas Company ("Boston Gas") or ComGas; (3) purchase gas directly from a producer with transportation provided by a pipeline and/or a LDC; and (4) purchase gas from other suppliers such as NEPCo, which is seeking blanket authorization to sell its contracted for gas supply if the market warrants (id., pp. 6, 7). EPEC noted that the availability of each of these options is likely to be dependent on the time of year and the cause of the shortfall in DOMAC supplies, but that several gas supply and transportation options are likely to be available at any given time (id., p. 6).

With regard to the first backup supply option, EPEC stated that the LNG industry is expanding worldwide and that several new suppliers are expected to enter the market in the mid to late 1990's (Exh. HO-PV-28, pp. 7, 8). EPEC stated that the expansion of the LNG industry would permit DOMAC to acquire LNG from other sources should Algerian LNG become unavailable for a period of time (id., p. 7). EPEC also indicated that several LNG storage terminals on the east and gulf coasts of the United States are being reopened or reevaluated (id., p. 7; Tr. 1, pp. 38-42, 53). EPEC stated that the development of expanded LNG trade in the Atlantic Basin offers the flexibility to divert shipments from one terminal to another should such a requirement be warranted (Exh. HO-PV-28, p. 8; Tr. 1, pp. 38-42, 53).[102]

With regard to the second backup supply option, EPEC stated that several LDCs in the region have contracted for substantial new supplies and pipeline capacity in anticipation of substantial growth in traditional and new markets (Exh. HO-PV-28, pp. 10, 11). EPEC stated that "there is a high probability that gas supplies and capacity could be available from one or a combination of LDCs for up to 11 months per year" in the near term (1992-1997) because of a combination of the

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102/ EPEC noted that DOMAC successfully arranged to divert a LNG delivery scheduled for Louisiana to Everett during the extremely cold month of December, 1989 (Exh. HO-PV-28, p. 8).

current economic slowdown and the pricing of gas to potential cogeneration customers (id.). EPEC indicated that Boston Gas, Bay State Gas Company ("Bay State") and ComGas are the most likely candidates to provide gas supplies on a short-term, off-peak basis if required (id.).

With regard to the third backup supply option, EPEC stated that during off-peak periods it could contract for gas supplies on the spot market to meet short-term needs in the event of a disruption in its firm DOMAC supplies (id., pp. 12, 13). EPEC stated that the availability of pipeline and LDC transportation capacity is the major constraint to making such purchases on a year-round basis (id.). EPEC stated that, at present, interruptible transportation capacity is available less than nine months per year on the interstate pipelines serving New England (Exh. HO-PV-28, p. 2). However, EPEC indicated that the planned expansion of pipeline capacity to the Northeast region is likely to facilitate the transportation of spot gas to the region (id., pp. 3, 12, 13). Specifically, EPEC stated that the expansion of pipeline capacity should extend the availability of interruptible pipeline gas to between 10 and 11 months per year in New England (id., p. 6, 11). EPEC asserted that this additional pipeline capacity would greatly enhance its ability to secure contingency gas supplies without relying directly on LDC capacity (id., p. 13).

With regard to the fourth backup supply option, EPEC stated that NEPCo has committed to purchasing a substantial quantity of natural gas and pipeline capacity in order to reduce air emissions from its existing generation facilities, fuel new generation to meet load growth, and diversify its fuel mix (id., p. 14). EPEC further indicated that NEPCo has filed an application at FERC to allow it to sell this gas to other markets if warranted (id.). EPEC stated that, should DOMAC supplies be disrupted, EPEC could purchase gas supplies from NEPCo while NEPCo uses oil in its Brayton Point facility (id.). EPEC indicated that it would be in both EPEC's and NEPCo's interests to agree to such an arrangement if DOMAC supply is curtailed, since NEPCo will purchase 57 percent of EPEC's output (id., pp. 14, 15).[103] NEPCo stated that gas destined for its Brayton Point Unit 4 facility potentially could be made available to the proposed project but that NEPCo has made no commitment to have back-up gas supplies available for the EPEC plant (Exhs. HO-RR-10, HO-RR-11; Tr. 2, pp. 23-26).

Finally, EPEC argued that its backup fuel supply "is functionally comparable" to the backup fuel supply plan of MASSPOWER, a facility previously approved by the Siting Council (EPEC Initial Brief at IV-23, IV-26).[104] EPEC asserted that the significance of MASSPOWER's 35 day oil back-up supply "is exceedingly modest" and "is transparently only a short-term solution" (id. at IV-22). EPEC asserted that the absence of such a back-up fuel supply in the case of the proposed EPEC project "only means a dip in that year's earnings (if the interruption occurs at the peak of winter and NEPCo then refuses to provide its gas) and no threat to the minimum availability

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103/ Mr. Hachey indicated that the proposed project's lack of a firm back-up fuel supply was an acceptable risk within NEPCo's overall portfolio approach to choosing new resources (Tr. 2, p. 75). Mr. Hachey explained that NEPCo "would not have a significant piece of its natural gas-fueled plants on-line without an oil backup" but saw no harm in having a single gas-fired project without backup oil supplies (id. at 74, 75).

104/ In MASSPOWER, the proponent identified several short-term and long-term backup fuel supply options in addition to two primary fuel supply options (20 DOMSC at 365-369). The short-term backup supply options identified by MASSPOWER were: (1) planned on-site oil storage sufficient for three days of operation; (2) purchases from an oil pipeline adjacent to that facility; and (3) potential leasing of nearby oil storage tanks. Id. at 365, 366. The long-term backup supply options identified were: (1) purchases of additional DOMAC supplies for a two-year period in the event of a delay in interstate pipeline construction; (2) spot gas purchases; (3) purchases from Bay State on all but the 20 coldest days of winter; and (4) oil-firing for a maximum of 70 consecutive days over two calendar years Id. at 366, 367. The two primary fuel supply options consisted of MASSPOWER (1) receiving 50 percent of its gas from pipeline sources and 50 percent from DOMAC to meet its requirements, and (2) receiving 100 percent of gas requirements from DOMAC. Id. at 361-365.

necessary for debt service" (id.).[105] EPEC further argued that the proposed EPEC project and MASSPOWER have "firm primary fuel supply plans of remarkable similarity" and that "both have no firm back-up fuel supply plans" (id. at IV-23).

EPEC's primary fuel acquisition strategy exhibits several important advantages for the proposed project. First, EPEC has acquired a long-term gas supply commitment that offers timely access to a firm 365-day fuel supply without the need for a major expansion of the interstate pipeline network. Second, the initial base price of EPEC's primary fuel supply is quite attractive. Third, the price escalators and price reopener provisions included in EPEC's supply contract ensure that the project's fuel supplies will remain reasonably priced relative to alternative fuels over time.

In MASSPOWER, the Siting Council approved a fuel acquisition strategy which featured a primary fuel supply plan which relies on a firm long-term LNG supply contract for 50 percent of that project's total fuel requirements (20 DOMSC at 368).[106] Here, the record indicates that, by virtue of the complex logistical chain involved in moving gas supplies from the wellhead in Algeria to their ultimate destination in Milford, DOMAC LNG is subject to a variety of potential supply contingencies. However, the record also indicates that, despite occasional supply disruptions, DOMAC has achieved an adequate record of reliability in the past. Thus, EPEC has demonstrated that DOMAC will likely serve as a reliable supplier of energy resources to the region in the future, and therefore, can be

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105/ EPEC noted that the proposed project could experience a supply disruption of approximately 36 days without suffering a financial penalty under the NEPCo contract, and that EPEC could still recover 90 percent of its fixed costs in the event of a 70 day outage (Exhs. HO-PV-28, p. 16, HO-PV-32).

106/ In MASSPOWER, the Siting Council approved the cogeneration facility subject to conditions, one of which related to MASSPOWER's fuel acquisition strategy (20 DOMSC at 370, 405). In a subsequent decision issued on December 19, 1990, the Siting Council found that MASSPOWER had complied with these conditions. MASSPOWER Inc., EFSC 89-100A (1990).

reasonably relied upon to provide the proposed project's total primary fuel requirements. Moreover, the use of LNG as a fuel adds to the diversity of the region's fuel mix for electricity generation.

In reviewing a project's fuel acquisition strategy, the Siting Council necessarily focuses on the project's primary fuel supply. However, backup fuel supplies and/or contingency plans for interruptions in primary fuel supplies also have consistently been considered by the Siting Council. In each of the Siting Council's previous decisions involving electric generating facilities, these facilities have had on-site storage of either the primary fuel or an alternative backup fuel. EEC, EFSC 90-100 at 117; West Lynn, EFSC 90-102 at 69; MASSPOWER, 20 DOMSC at 359-368; Altresco-Pittsfield, 18 DOMSC at 384-389. Here, the proposed EPEC project has neither on-site storage of its primary fuel nor an alternative backup fuel.

Clearly, the existence of dedicated on-site fuel storage capacity provides a high degree of confidence that a generating facility will be able to continue to produce electricity for at least a short period of time in the event of a disruption in the facilities' primary fuel supply. Further, a generating facility which can run on two different types of fuels has certain inherent reliability advantages compared to an equivalent facility which can run on only one. Quite simply, a dual-fuel facility can switch to an alternative fuel in the event of a disruption in the supply of one fuel.

Here, EPEC has identified several backup fuel supply options, all of which in one form or another rely on gas supplies which EPEC does not currently have under contract. EPEC's assertion that its backup fuel supply plan is essentially equivalent to MASSPOWER's is not supported by the record, since the EPEC facility does not have either dedicated on-site fuel storage or the ability to use an alternative fuel as the MASSPOWER facility had.

Nevertheless, EPEC has identified a range of backup fuel supply options which together constitute a reasonable backup fuel supply strategy.[107] First, EPEC has shown that the proposed project will be reasonably likely to be able to obtain interruptible gas supplies during most of the year.[108] Second, EPEC has shown that the Atlantic Basin LNG supply infrastructure is becoming increasingly flexible with the entrance of new producers, additional tankers, and the reopening of LNG terminals in the United States. Thus, LNG is becoming less vulnerable to potential supply contingencies associated with a single tanker or a single producer. Third, EPEC has described the potential for using NEPCo's firm pipeline supplies in the event of a LNG supply disruption.

The Siting Council notes that it appears that a fuel sharing arrangement between EPEC and NEPCo could provide significant benefits to both parties in the event of a disruption in EPEC's LNG supplies. The Siting Council expects EPEC to attempt to formalize such an agreement with NEPCo.

In summary, EPEC has formulated a fuel acquisition strategy that includes a reasonably reliable primary fuel supply and a reasonable set of backup fuel supply options. Moreover, EPEC's primary fuel supply contract with DOMAC includes (1) an advantageous initial fuel supply price, and (2) a commodity price indexed to NEPOOL's AFFI and price reopener provisions, which together should ensure that the project's fuel supply will remain attractive over time in terms of price.

107/ We note that EPEC's argument that the proposed project could experience a supply disruption of approximately 36 days without suffering a financial penalty under the NEPCo contract, while relevant to the Siting Council's assessment of the project's financial viability (see Section II.C.2, above), is irrelevant to our assessment of the adequacy of EPEC's fuel supply strategy.

108/ We note that EPEC's assertions that the availability of interruptible pipeline gas in New England will increase over the next several years appears to be reasonable based on the record in this case. However, as the region's demand for firm gas supplies increases over time, the availability of interruptible gas supplies will presumably begin to decline towards historical levels.

Accordingly, the Siting Council finds that EPEC has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the term of its power purchase agreements. The Siting Council has found that EPEC has established that (1) the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the life of its PPAs. Accordingly, the Siting Council finds that EPEC has established that the proposed project meets the Siting Council's second test of viability.

4. Conclusions on Project Viability

The Siting Council has found that EPEC has established that its proposed project (1) upon compliance with the above ORDER, is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) is likely to operate and be a reliable, least-cost source of energy over the life of its PPAs.

Accordingly, the Siting Council finds that EPEC has established that its proposed project is likely to be a viable source of energy.

D. Conclusions on the Proposed Project

The Siting Council has found that: (1) New England needs at least 146 MW of additional energy resources from the proposed project for reliability or economic efficiency purposes beginning in the 1994 to 1995 period, and beyond; and (2) the proposed project is likely to provide benefits to the Commonwealth of sufficient magnitude to offset the impacts on the Commonwealth's resources from the construction and operation of the proposed facility. The Siting Council also has found that the proposed project is consistent with the resource use and development policies of the Commonwealth. In addition, the Siting Council has found that the proposed project (1) upon compliance with the above ORDER is reasonably likely to be financed and constructed so that the project will actually go into service as planned and be capable of meeting performance objectives and (2) is likely to operate and be a reliable, least-cost source of energy over the life of its PPAs.

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 facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In order to determine whether the facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Council has required a facility proponent to demonstrate that it has examined a reasonable range of practical facility siting alternatives. EEC, EFSC 90-100 at 122; West Lynn, EFSC 90-102 at 73; 1991 NEPCo Decision, EFSC 89-24A at 48; Bay State Gas Company, EFSC 89-13, p. 40 (1990) ("1900 Bay State Gas Decision"); MASSPOWER, 20 DOMSC at 371; Berkshire Gas Company (Phase II), 20 DOMSC 109, 148 (1990) ("1990 Berkshire Decision"); Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 38-42 (1989) ("BECo/MWRA"); Turners Falls, 18 DOMSC at 175-178; Braintree Electric Light Department, 18 DOMSC 1, 31-40 (1988) ("1988 Braintree Decision"); Altresco-Pittsfield, 17 DOMSC at 387; NEA, 16 DOMSC at 381-409. 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. First, the facility proponent must establish that it has developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. EEC, EFSC 90-100 at 122-123; West Lynn, EFSC 90-102 at 73; 1991 NEPCo Decision, 89-24A at 48-49; 1990 Bay State Gas Decision, EFSC 89-13 at 40-41; MASSPOWER, 20 DOMSC at 373-374, 382; 1990 Berkshire Decision, 20 DOMSC at

148-149, 151-156. Second, the facility proponent must establish that it has identified at least two noticed sites or routes with some measure of geographic diversity.[109] EEC, EFSC 90-100 at 123; West Lynn, EFSC 90-102 at 73-74; 1991 NEPCo Decision, EFSC 89-24A at 48-49; 1990 Bay State Gas Decision, EFSC 89-13 at 40-41; MASSPOWER, 20 DOMSC at 371-372; 1990 Berkshire Decision, 20 DOMSC at 148; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; Commonwealth Electric Company, 17 DOMSC 249, 301-303 (1988) ("1988 Com/Electric Decision"); NEA, 16 DOMSC at 381-409.

Finally, in order to determine whether the facility proponent has shown that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability, the facility proponent must demonstrate that the proposed site for the facility is superior to the noticed alternative on the basis of balancing cost, environmental impact and reliability of supply. EEC, EFSC 90-100 at 123; West Lynn, EFSC 90-102 at 73-74; 1991 NEPCo Decision, EFSC 89-24A at 49-51; 1990 Bay State Gas Decision, EFSC 89-13 at 43; MASSPOWER, 20 DOMSC at 382; 1990 Berkshire Decision, 20 DOMSC at 148; BECO/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178.

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

B. Description of the Proposed and Alternative Facilities

EPEC proposes to construct a 146 MW combined cycle, gas-fired facility at one of two sites in the Town of Milford (Exh. EPEC-19, p. 2-1). The primary site is a 6.8-acre parcel of land in an industrially zoned area approximately one mile southeast of Milford Center. The primary site is owned by Fafard realty, and currently is leased as a transportation terminal for tractor trailor vehicles by Foster-Forbes, which owns and operates a glass manufacturing facility on the south side of National Street across the street from the primary site (id., p. 2-2). The site is bordered on the east by a Conrail ROW, on the south by National Street, on the west by a cemetery, and on the north by vacant land and the Godfrey Brook, a tributary of the Charles River (id.).

The major components of the proposed facility at the primary site include a single gas-fired turbine generator, an exhaust heat recovery steam generator, a steam turbine generator, a mechanically induced draft cooling tower, a 100-foot exhaust stack, a 1,000-foot sewer line which would connect to a planned Town of Milford sewer line, a 14-inch pipeline to carry wastewater effluent for cooling from the MWTP located approximately 3,500 feet to the south of the primary site, an electrical switchyard on the northern portion of the site adjacent to the Conrail ROW, a 68,000 gallon stormwater retention pond located along the northern border of the site, and an ammonia storage tank next to a 500,000-gallon above-ground water storage tank and a 300,000-gallon demineralized water storage tank along the southern, National Street border of the site (id., pp. 2-1, 2-15, 6-86, Figure 2.2.2-1).

Potable water and demineralizer make-up water would be withdrawn from the MWC (id., p. 2-10). As indicated above, cooling water would consist of treated effluent obtained from the MWTP (id., p. 2-10). Cooling tower discharge water would be returned to the MWTP along with facility wastewater (id.,

p. 2-15). Air emissions would be controlled through the utilization of steam injection and SCR (id., p. 2-18).

The proposed facility would be fueled solely by natural gas, delivered through a 200-foot gas pipeline which would tap into a new 3.1-mile pipeline to be constructed by Algonquin (Exhs. EPEC-19, p. 1-1, HO-PV-34). The gas would be supplied by DOMAC exclusively from LNG (Exh. EPEC-1, p. I-47).

Electricity output would be transmitted from a new switchyard in the northern portion of the primary site by two 1,000-foot, 115 kV transmission lines (Exh. HO-RR-79). These lines would extend along each side of the Conrail ROW to the NEPCo 115 kV transmission system north of the site (id.).

The proposed facility would cost approximately $126.3 million in 1990 dollars at the primary site (Exhs. HO-C-1, HO-C-10).

The alternative site consists of 48 acres of undeveloped, heavily wooded, hilly land located approximately one mile east of Milford Center (Exh. EPEC-8, p. 2-25). This site is owned by the Town of Milford and is zoned highway industrial but bordered on the north by undeveloped commercially zoned land and on the other three sides by undeveloped residentially zoned land (id., 2-29). The proposed facility would be located in the northeastern corner of the site (id.).

The same major components of the proposed facility would be constructed on the alternative site. A 2,300-foot transmission line would connect the proposed facility at the alternative site to the same NEPCo 115 kV transmission line that would be utilized by the primary site (id.). A 1.5-mile natural gas pipeline would transport gas from the Algonquin pipeline (id., pp. 2-29, 2-35). A 2.5-mile effluent pipeline would be constructed from MWTP and a 9,700-foot sewer line would return facility wastewater to the Milford sewer system (id., p. 2-35).

The proposed facility would cost approximately $133.3 million in 1990 dollars at the alternative site (Exh. EPEC-1, pp. III-21, III-24).

C. Site Selection Process

EPEC asserted that it has developed a reasonable set of criteria for identifying a range of practical alternative sites in accordance with Siting Council standards and precedent (Exh. EPEC-1, pp. III-1, III-4). EPEC stated that its criteria reflected development feasibility, cost impacts, and environmental impacts (id., p. III-3). The following sections discuss EPEC's development and application of its siting criteria as part of its site selection process.

1. Development of Siting Criteria

EPEC provided two sets of siting criteria, each serving as a different iteration of the screening process (id., pp. III-2, III-26). The first set of criteria ("site screening criteria") was used to identify a pool of practical siting alternatives and to screen that pool of alternative sites to select a few for detailed analysis (id., pp. III-1 to III-4). The second set of criteria ("environmental criteria") was used to assess detailed environmental issues pertaining to Siting Council and MEPA requirements (id., pp. III-24 to III-28). EPEC indicated that it utilized the second set of environmental criteria to evaluate the final sites selected for public notice and to choose the primary site (id., p. III-24).

With respect to identification and preliminary screening of alternative sites, EPEC stated that it developed the following set of site screening criteria: (1) electric transmission access -- i.e., location near a transmission line with a voltage of 115 kV or greater and with the ability to handle the output of the proposed facility; (2) fuel transportation access -- i.e., reasonable access to a suitable gas pipeline without the need for substantial upgrades; (3) water supply availability; (4) site size -- i.e., a minimum of four to five acres; (5) site zoning -- i.e., industrial zoning or a similar zoning category which would allow the construction of the project without the need for significant zoning variances; (6) site availability; and (7) environmental compatibility -- i.e., a location away from dense residential areas, outside of non-attainment areas for certain air quality pollutants, and exhibiting reasonably acceptable existing environmental conditions (id., pp. III-2, III-3). EPEC indicated that virtually all of the above criteria represent potential "fatal flaws" which could result in rendering a potential site infeasible (id., p. III-3). In addition, EPEC stated that community acceptance of the proposed project was an important threshold factor which was analyzed prior to the application of the aforementioned set of site screening criteria (id., p. III-5).

EPEC stated that it developed its environmental criteria in conjunction with Charles T. Main, Inc., in order to evaluate the environmental impacts of the sites which remained after EPEC applied its site screening criteria (id., p. III-24). EPEC stated that the environmental criteria consisted of the following: (1) earth resources; (2) wetlands; (3) water resources; (4) vegetation; (5) fish and wildlife; (6) rare and endangered species; (7) land use; (8) socioeconomic conditions; (9) open space and recreation; (10) cultural resources; (11) visual environment; (12) noise; (13) air quality; (14) transportation/traffic; (15) utility interconnection requirements; and (16) solid waste and hazardous waste (Exh. EPEC-1, Tables 3.6.1 and 3.6.18).

EPEC indicated that it utilized a relative weighting methodology to identify siting alternatives, but did not include precise numerical values of weights, which it viewed as rigid and unrealistic (id., pp. III-1, III-4). EPEC assigned the highest relative weights to those criteria which are most likely to have positive effects in meeting the primary siting objectives (id., p. III-5). Specifically, EPEC ranked the criteria in order of their relative weight as follows: (1) electric transmission and fuel access; (2) water supply, wastewater discharge, and other environmental compatibility factors; and (3) site size, availability, and zoning (id.).

The Siting Council notes that, while this is the first time it has reviewed a proposal to construct an IPP, the site selection criteria developed for an IPP should be similar to criteria developed for a cogeneration facility, except that an IPP need not be located near a steam host. Both IPPs and cogeneration facilities are affected by such criteria as access to transmission lines, fuel supplies and water sources; size, zoning, and availability of the site; development costs; and environmental impacts. Here, EPEC has considered such criteria in its site screening process. In addition, the environmental criteria were developed by EPEC in accordance with MEPA requirements in order to identify specific environmental impacts at potential sites. Therefore, the site selection criteria developed by EPEC are consistent with the site selection criteria which the Siting Council has found to be appropriate for cogeneration facilities. EEC, EFSC 90-100 at 129; West Lynn, EFSC 90-102 at 102; MASSPOWER, 20 DOMSC at 378-379.

In regard to EPEC's use of relative weights, the Siting Council notes that EPEC has attempted to rank its criteria in a non-quantitative manner. However, EPEC did not identify the specific means by which it compared criteria within its three separate weight categories or across categories. Rather, EPEC simply stated its aversion to the use of numerical values for weights (id., pp. 4-5). The Siting Council consistently has raised concerns regarding the absence of a specific means of weighting in a company's site selection criteria. EEC, EFSC 90-100 at 129; West Lynn, EFSC 90-102 at 79; MASSPOWER, 20 DOMSC at 378-379; 1990 Berkshire Decision, 20 DOMSC at 161-162. In requiring the assignment of weights or values, the Siting Council does not suggest that such weights and values can or should operate as a substitute for judgment. Instead, the Siting Council recognizes that judgment inherently requires the assignment of some weights or values to specific criteria, and that our review of such weights provides us with the means to determine whether a company has used appropriate judgment and applied its criteria consistently.

Nevertheless, the Siting Council finds that EPEC has developed a reasonable set of criteria for identifying and evaluating alternative sites.

2. Application of Siting Criteria

EPEC stated that it had originally identified a parcel of property located in Lynn ("Lynn Boston Gas site") as the preferred site for the proposed facility (Exh. EPEC-1, p. I-22). However, since the Lynn Boston Gas site was the subject of an ongoing clean-up of hazardous waste contamination, EPEC decided to broaden its pool of potential sites (id.). EPEC then located potential development areas on United States Geological Survey ("USGS") maps in close proximity to the Algonquin pipeline system and NEPCo transmission lines (Exh. EPEC-11). In addition, EPEC stated it investigated approximately 30 possible sites identified by Dominion Energy, Inc., and a list of 300 sites previously identified by a consultant for possible water treatment sites (id.).

EPEC applied its set of site screening criteria to narrow this large group of potential sites to a total of nine sites for more detailed assessment (Exh. HO-B-8). In November 1989, Charles T. Main, Inc., developed a preliminary site screening report ("Main Report") for these nine sites (id.). EPEC stated that the alternative site in Milford was identified as a tenth site for assessment later during discussions with officials of the Town of Milford (Exh. EPEC-1, p. III-23). Based on the more detailed evaluation included in the Main Report, EPEC selected the Lynn Boston Gas site, the primary site in Milford, and the Hood Enterprise site in Uxbridge as the three sites that warranted further review (Exh. HO-B-8). EPEC indicated that eventually the alternative site was substituted for the Lynn Boston Gas site because of the length of time necessary to clean up the contamination at the latter (Exh. EPEC-1, p. III-9). EPEC stated that public concerns about the adequacy of water for cooling the proposed facility in Uxbridge led it to pursue the Milford primary and alternative sites (id.). EPEC further noted that Milford Town officials had provided positive feedback regarding the location of the proposed project in Milford (id.).

The record indicates that the primary site is a parcel of land consisting of a total of 6.8 acres, with the adjacent Lot 2 of 6.3 acres available for potential use as a drainage basin (Exhs. EPEC-19, p. 2-1, HO-PV-37). The Town site is substantially larger, consisting of approximately 48 acres (Exh. EPEC-8, p. 2-25). EPEC maintained that site size, zoning, and availability are adequate for both sites (Exh. EPEC-1, p. III-24). EPEC asserted that the primary site is superior to the alternative site in terms of the costs associated with existing utility infrastructure, land acquisition, and site preparation (id.). EPEC stated that of its 17 environmental criteria, the primary site was preferred for ten of the criteria, the alternative site was preferred for two of the criteria, and that both sites were rated equally for five of the criteria (id., p. III-90).

EPEC determined that the primary site is superior to the alternative site based on its location within a previously developed industrial zone and its superior environmental impacts (id., p. I-25). However, EPEC asserted that both sites appear to be free of any fatal flaws (id., p. III-92).

In regard to the selection of specific sites on which to locate the proposed facility, EPEC undertook a comprehensive search for available sites. The use of locational indicators and various informational resources coupled with referrals resulted in the identification of over 300 initial alternative sites. The Siting Council notes that the site selection process for an IPP generally should involve the consideration of a broader list of alternatives than other proposed energy projects such as cogeneration facilities, transmission lines, and gas pipelines as an IPP is not constrained by the necessity to locate in a specific area, such as near a steam host. The record shows that EPEC applied its screening criteria to the ten preliminary alternatives, ultimately selecting three sites as the final alternatives. However, upon application of the community acceptance threshold requirement, EPEC focused on a primary site and only one alternative site. EPEC then subjected the final sites to intensive environmental scrutiny.

Accordingly, the Siting Council finds that EPEC has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures it has not overlooked or eliminated any clearly superior sites.

3. Geographic Diversity

In this section, the Siting Council considers the second prong of the practicality test -- whether EPEC's site selection process included consideration of site alternatives with some measure of geographic diversity. EPEC stated that the selection of two sites 1.1 miles apart meets the Siting Council's geographic diversity requirement (EPEC Initial Brief, p. V-8). In addition, EPEC asserted that the two sites generate distinct impacts, underscoring the degree of geographic diversity (id.).

The Siting Council requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity.[110] 1991 NEPCo Decision, EFSC 89-24A at 63-66; 1990 Berkshire Decision, 20 DOMSC at 181-182. The Siting Council notes that there is no minimum distance that is sufficient to establish geographic diversity in any specific case. The Siting Council previously determined that two sites in the same town can provide adequate geographic diversity for a generating facility review. NEA, 16 DOMSC at 385-388. Further, in a recent transmission line case, the Siting Council stated

110/ In MASSPOWER, the Siting Council set forth a standard that, if met, would exempt certain cogeneration facilities from the noticed alternative requirement (20 DOMSC at 382). However, non-utility proposals to construct IPPs, utility proposals to construct generating facilities, and proposals to construct transmission lines and gas pipelines must provide a noticed alternative.

that simple quantitative diversity thresholds were not appropriate for evaluating geographic diversity. 1991 NEPCo Decision, EFSC 89-24A at 65. In that case, the Siting Council concluded that the facts must be examined on a case-by-case basis to determine whether two routes were sufficiently distinct to meet the geographic diversity standard. Id. at 66. To determine whether sufficient geographic diversity exists between two proposed sites for a proposed generating facility, the specific characteristics of each site must be scrutinized as well as the locational separation.

Here, EPEC has provided two sites located 1.1 miles apart in the same town. Nonetheless, the two sites vary significantly in environmental characteristics. For example, one is disturbed land while the other is wooded, and they have different sizes and abutting land uses.

Accordingly, based on the foregoing, the Siting Council finds that EPEC has identified at least two practical sites with a sufficient measure of geographic diversity.

4. Conclusion on the Site Selection Process

The Siting Council has found that: (1) EPEC has developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) EPEC has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures it has not overlooked or eliminated any clearly superior sites; and (3) EPEC has identified at least two practical sites with a sufficient measure of geographic diversity.

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

D. Cost Analysis of the Proposed Facilities and Alternative Facilities

In this section, the Siting Council evaluates the proposed facilities to determine whether the cost estimates associated with construction are realistic for a facility of the size and the design of the EPEC facility. The Siting Council also compares the estimated costs of constructing the proposed facility on the primary and alternative sites.

With respect to whether the cost estimates associated with construction of the proposed facilities are realistic for a facility of the size and the design of the EPEC facility, EPEC provided an analysis comparing the estimated costs of the proposed facility with the costs of a generic gas-fired combined-cycle facility (Exh. HO-C-10). EPEC stated that its estimate of the gross cost of plant and equipment for the EPEC project, amounting to $1,030 per kW in 1993 dollars, is approximately 3 percent lower than the escalated cost identified for the comparable combined-cycle technology in the Electric Power Research Institute's ("EPRI") 1986 Technical Assessment Guide (Exhs. EPEC-1, pp. II-42 to II-44; HO-C-10). EPEC further indicated that, after factoring in fixed and variable O&M costs and other factors, the expected levelized cost of power from the proposed project over its life would be 8.87 cents per kwh as opposed to 8.84 cents per kwh for the generic plant (Exh. HO-C-10).

Accordingly, based on the above, the Siting Council finds that EPEC has established that the cost estimates associated with the proposed facilities at the primary site or alternate site are realistic for a facility of the size and design of the proposed facility.

With respect to the cost comparison of the primary and alternative sites for the proposed facility, EPEC estimated that the total installation costs of the proposed facilities at the primary site, which include project development as well as construction costs, would total about $126.3 million (1990 dollars) (Exhs. HO-C-1, HO-C-10). EPEC indicated that its estimate includes the costs of engineering, project management, plant and equipment, site preparation, gas pipeline interconnection, electric transmission line interconnection, water and effluent line interconnections, interest during construction, working capital, startup activities, financing, land, and escalation and contingency costs (id.).

EPEC estimated that it would require an additional $7 million in infrastructure costs to site the proposed facilities at the alternative site (Exh. EPEC-1, pp. III-21, III-24). EPEC identified six areas in which infrastructure cost differences exist between the two sites: (1) land acquisition; (2) gas pipeline interconnection; (3) electric transmission line interconnection; (4) potable water supply interconnection; (5) wastewater effluent and sewer line interconnections; and (6) site preparation (id., pp. III-18 to III-24).

With respect to land acquisition, EPEC estimated that the primary site would cost approximately $1.1 million, compared to a cost of approximately $3.1 million for the alternative site (id., p. III-21; Exh. HO-PV-37; Tr. 7, p. 62).

With respect to the gas pipeline interconnection, EPEC stated that construction of the proposed facilities at the alternative site would require the construction of a new high pressure pipeline of approximately 1.5 miles in length, which EPEC estimated would cost $1.5 million more to construct than the construction of the 200-foot gas pipeline that would be required to serve the proposed facilities at the primary site (Exh. EPEC-1, p. III-20).

With respect to the electric transmission line interconnection, EPEC initially stated that it would cost approximately $154,000 to construct a new, single 1,000-foot transmission line to connect the proposed facilities with the existing electric grid at the primary site (id., pp. III-18, III-20). EPEC also stated that it would cost an estimated $354,000 to construct a new, single 2,300-foot transmission line to connect the proposed facilities with the existing electric grid at the alternative site (id.).[111]

With respect to the potable water supply interconnection, EPEC estimated that, an additional 700 feet of 12-inch water line would be needed to provide the proposed facilities at the alternative site with potable water, and that the additional cost of such construction would be about $50,000 (Exh. EPEC-1, p. III-20).

With respect to the wastewater effluent line, EPEC stated that construction of the proposed facilities at the alternative site would require the construction of approximately 1.5 miles of new effluent line in addition to the 0.75 miles of effluent line required to serve the proposed facilities at the primary site (id.). EPEC estimated that the additional cost of the effluent line required to serve the proposed facilities at the alternative site would be about $1.25 million (id.). EPEC further estimated that the wastewater sewer line required for the proposed facilities at the alternative site would be 7,900 feet longer and cost $1.25 million more than the wastewater sewer line required to serve the proposed facilities at the primary site (id., pp. III-20 to III-22).

OEPEC estimated that the costs required to prepare the alternative site would be about $750,000 higher than the costs to prepare the primary site (id., pp. III-23, III-24). EPEC stated that minimal site preparation would be required at the primary site, which is flat and generally devoid of vegetation (id., p. III-23). EPEC further stated that the alternative site is heavily wooded, hilly and rocky, and therefore, would require a significant amount of site preparation, including the

111/ EPEC later indicated, however, that it planned to construct two parallel overhead transmission lines to connect the proposed facilities with the existing electric grid at either the primary or alternative sites (Exh. EPEC-8, pp. 2-19, 2-29; Tr. 6, pp. 49). EPEC stated that the cost to construct these lines at the primary site would be approximately $700,000 (Exh. HO-RR-79). EPEC did not provide an estimate for the alternative site.

construction of a new access road, removal of a large number of trees and a significant amount of grading (id.; Tr. 7, p. 62).

Finally, EPEC provided evidence that the financing, contingency, and escalation costs associated with the proposed facilities would be lower for the primary site than for the alternative site (Exh. HO-C-1). EPEC stated that these higher costs in part would be the result of the longer construction time required for the alternative site related to site preparation (Tr. 7, pp. 63-64).[112]

Based on the above, the Siting Council finds that EPEC has demonstrated that the costs of constructing and operating the proposed facilities at the primary site would be less than constructing the proposed facilities at the alternative site. Accordingly, the Siting Council finds that construction and operation of the proposed facilities at the primary site is preferable to construction of the proposed facilities at the alternative site on the basis of cost.

112/ EPEC stated that, in order to conform with MDEP noise standards, the use of the alternative site would require extensive project redesign and noise mitigation in addition to that planned for the proposed site (Exh. EPEC-8, p. 5-34; Tr. 9, p. 68). EPEC did not provide an estimate of the cost of such additional mitigation, but stated that the cost of redesign and noise mitigation is expected to be within the overall project budget (Tr. 9, pp. 68-69). See Section III.E.7 for a discussion of noise impacts.

E. Environmental Analysis of the Proposed and Alternative Facilities

1. Standard of Review

In this section, the Siting Council examines the environmental impacts of the proposed facilities at the primary and alternative sites in order to determine (1) whether these impacts are acceptable, and (2) which site is preferable with regard to environmental impacts. In order to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Council balances the environmental impacts of the proposed facilities against the cost and reliability impacts of such facilities.

During the course of the proceeding, Bellingham and CCAP commented on the Siting Council's minimum environmental impact standard, and proposed an additional standard for analyzing the minimum environmental impacts of proposed facilities. Bellingham and CCAP argued that, in order to conclude that a proposed facility would impose a minimum impact on the environment in accordance with G.L. c. 164, sec. 69H, the Siting Council must "find that standing alone, a proposed plant nonetheless has a minimum impact on the environment, without regard to comparisons" (Bellingham Initial Brief, pp. 3-4; CCAP Brief, pp. 3-5).

In EEC, the Attorney General proposed the adoption of a similar standard (EFSC 90-102 at 141-142). In that decision, the Siting Council rejected the Attorney General's argument. Id. at 142-145. In EEC, we noted that the Siting Council's mandate does not require that the Siting Council develop and apply a separate and more stringent level of environmental control for energy facilities relative to the requirement of other environmental permitting agencies (EFSC 90-102 at 142). Rather, we stated that the mandate requires that the Siting Council ensure that all energy facilities achieve the appropriate balance between minimizing environmental impacts and minimizing cost, consistent with meeting reliability objectives for energy supply. Id. We also stated that an overall assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved among conflicting environmental concerns as well as between environmental impacts, cost and reliability. Id. at 143-144. We further stated that a facility proposal which achieves that appropriate balance is one that meets the Siting Council's statutory standard to minimize environmental impacts. Id. at 144.

In past cases, the Siting Council has balanced conflicting environmental concerns as well as environmental, cost and reliability concerns. Accordingly, here, the Siting Council concludes that a facility which minimizes environmental impacts is one which achieves an appropriate balance (1) among various environmental impacts, and (2) among environmental impacts, costs and reliability.

2. Water Supply

a. Potable Water

EPEC stated that the proposed generating facility, whether located at the primary site or the alternative site, would require approximately 240,000 gallons per day of potable water for a number of plant operations, including boiler makeup (or replacement), gas turbine steam injection, domestic use, fire protection, and general plant service (Exhs. HO-E-1, HO-E-29, EPEC-8, p. 2-13).[113]

EPEC stated that potable water would be supplied to the facility by the MWC, a private corporation located in the Town of Milford (Exh. HO-RR-57).

113/ EPEC stated that it intends to supplement the 1.02 million gallons per day ("MGD") of effluent cooling water with potable water during periods of low streamflow in the upper Charles River (Exh. EPEC-8, p. ES-3). The Siting Council examines the availability of potable water to supplement effluent cooling water in Section III.F, below.

EPEC indicated that the MWC provides water to residential, commercial and industrial customers in the Town of Milford and to wholesale customers in the Towns of Hopedale, Mendon and Medway (Exh. HO-E-27, "Report on Additional Water Supply for the MWC," p. 1). EPEC also indicated that MWC would sell potable water to EPEC at a price of $7,241.64 per month for continuous flow of 240,000 gallons per day, pursuant to a tariff currently on file with the MDPU (Exh. HO-B-8; Tr. 4, pp. 150-151, Tr. 7, pp. 34-35).

EPEC provided a copy of the current water withdrawal permit issued by the MDEP to the MWC (Exh. HO-RR-57). EPEC stated that the MDEP water withdrawal permit establishes limits on the maximum average daily water withdrawal and total annual water withdrawal which may be made by the MWC during the period from 1989 to 2009 (id.; Exh. EPEC-8, p. 3-79). EPEC also stated that the amount of water allowed for withdrawal under the permit is based upon projections of water demand made by the Massachusetts Department of Environmental Management ("MDEM") and an assessment of the impacts of the proposed withdrawal (id.; Tr. 10, pp. 81-84, 101-104). CRWA's witness, Andrew Gottlieb, testified that the MDEM projection of demand assumes proportional growth in the residential, commercial and industrial sectors, based upon the current zoning within the communities served by the water supplier (Exh. CRWA-1; Tr. 10, pp. 94-96).[114]

EPEC stated that the water withdrawal permit indicates that MWC's allowable maximum daily average water withdrawal increases from 4.1 MGD in 1989 to 5.32 MGD in 2009 (Exh. HO-RR-57). EPEC also stated that MWC's demand has

114/ EPEC indicated that the land for the primary site is zoned industrial/commercial, and the land for the alternative site is zoned highway industrial (Exh. EPEC-8, pp. 3-155, 3-221). EPEC explained that both of these zoning categories allow heavy industrial uses (id.). EPEC further indicated that 240,000 gallons per day of potable water is not an unusual water requirement by an industrial user (Tr. 4, p. 54).

declined in recent years, and that actual 1989 demand was 2.9 MGD, which is 1.2 MGD less than the projected demand or the allowed withdrawal for that year under its MDEP permit (Exh. EPEC-8, p. 3-81). EPEC further stated that the water withdrawal permit also indicates that the total safe yield of the MWC's existing permitted water sources is 5.18 MGD, with an additional 0.95 MGD for emergency use (Exh. HO-RR-57). EPEC argued that the MWC has a very good history of obtaining supplies that are adequate to meet its demand (EPEC Initial Brief, pp. V-41 to V-42). Further, EPEC's witness, Mr. Gerath, testified that in conversations with representatives of MDEM and MDEP, no concerns were expressed regarding the ability of MWC to meet its projected demand by the year 2009 despite the 0.14 MGD difference between the projected demand of 5.32 MGD and available non-emergency supplies of 5.18 MGD (Tr. 5, pp. 9-10).

The record demonstrates that the MDEM projections of future demand, which form the basis for water withdrawal permits, incorporate generic assumptions regarding development of industrially zoned land for industrial uses. Thus, projected demand for water assumes eventual industrial development at the primary and alternative sites. Further, even if the quantity of potable water required by the proposed facility were not included in MDEM's demand projections, the record in this proceeding demonstrates that EPEC's planned use of 240,000 gallons per day of potable water is well within the 1.2 MGD "cushion" between MWC's allowable withdrawals under its permit and the actual demand for water in 1989. Accepting MDEM's projections of growth in water demand, this "cushion" should remain in place over the forecast period as permitted withdrawal levels increase together with projected demand levels. Finally, the relatively small difference between MWC's projected demand and the available non-emergency supply by the year 2009 (0.14 MGD) is well within this cushion. Accordingly, the Siting Council finds that the MWC's supply of potable water is adequate to meet the potable water requirements of the proposed EPEC facility at either the primary site or the alternative site.

b. Effluent

EPEC asserted that the proposed generating facility, whether located at the primary site or at the alternative site, would use approximately 1.02 MGD, or 1.35 cubic feet per second ("cfs"), of treated wastewater effluent for cooling purposes (Exhs. HO-E-2, HO-E-29, EPEC-8, pp. 2-11, 4-32).

EPEC maintained that effluent would be provided to the proposed facility from the Milford Wastewater Treatment Plant ("MWTP") (Exh. EPEC-8, p. 2-11).[115] EPEC indicated that the MWTP is designed for an average daily outflow of 4.3 MGD, which is discharged into the Charles River (Exh. HO-E-3). EPEC also indicated that the current average daily flow from the MWTP is five cfs, and that the minimum daily flow recorded by the MWTP since its 1986 upgrade is 2.83 cfs (Exh. EPEC-8, pp. 3-66 to 3-69).[116] EPEC provided a copy of an executed agreement between MPLP and the Town of Milford Sewer Commissioners and the Town of Milford Board of Selectmen for the purchase by MPLP of up to 1.5 MGD of effluent from the MWTP (Exh. HO-PV-33(3) (Sup.)). EPEC stated that the agreement for purchase of effluent specifies that MPLP shall have prior right, over all other potential users, to purchase effluent from the MWTP (id.). EPEC further stated that the agreement for purchase of effluent specifies that other potential users of effluent may purchase or acquire only those volumes which were made available to MPLP on a day-to-day basis, and which MPLP affirmatively declined (id.). Finally, EPEC indicated that no other uses

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115/ EPEC indicated that the MWTP was constructed in 1906, and that it was upgraded to a tertiary, or advanced, treatment system in 1986 (Exhs. HO-RR-56, HO-B-8). EPEC also indicated that the MWTP is designed such that operations would be interrupted only in the event of a natural disaster such as an earthquake (id.).

116/ EPEC's witness, Mark Gerath, testified that the MWTP flow has increased over time, and that flow is expected to continue to increase as the MWC demand for water increases (Tr. 4, p. 95).

currently are planned for the MWTP effluent (Exhs. HO-E-3, HO-RR-81).

In response to concerns that have been raised regarding the diversion of effluent to the proposed facility that would otherwise be discharged into the Charles River (see Section III.E.3, below), EPEC asserted that it would not purchase effluent from the MWTP when such purchases would cause the streamflow of the upper Charles River to fall below three cfs (Exh. EPEC-8, p. ES-3). During such low flow events, EPEC has stated that it would use water to be stored at the project site, purchase supplemental potable water from the MWC, or modify plant operations to reduce the need for cooling water (id.). Additionally, EPEC indicated that sales of effluent to users other than the proposed project would be curtailed by the MWTP when streamflow in the upper Charles River is at or below 150 percent of the level at which MPLP would employ its cooling water mitigation strategy (Exh. HO-PV-33 (Sup.)).

The proposed facility's cooling water requirement of 1.02 MGD clearly is within the 4.3 MGD average design capacity of the MWTP. Further, the anticipated diversion of 1.35 cfs to the proposed EPEC facility is less than half of the minimum outflow recorded at the MWTP in recent years. Finally, the record demonstrates that no uses are planned for MWTP effluent other than the proposed EPEC facility. Accordingly, the Siting Council finds that the supply of effluent from the MWTP is adequate to meet the requirements of the proposed facility at either the primary site or the alternative site when streamflow in the upper Charles River is above three cfs.

The Siting Council notes that EPEC has identified concrete steps, including modification of the proposed facility's operations, which it would take when streamflow in the upper Charles River falls below three cfs. The Siting Council examines the ability of EPEC to implement these steps and the reliability implications of these steps in Section III.F, below.

3. Impact of the Proposed Effluent Diversion on Waterways

In this section, the Siting Council reviews the impact on waterways of the proposed effluent diversion. As noted in Section III.E.2.b, above, the proposed facilities would require 1.35 cfs of treated wastewater effluent for cooling purposes (Exhs. HO-E-2, HO-E-29, EPEC-8, pp. 2-11, 4-32). The effluent, which would be supplied to the proposed facility by MWTP, would otherwise be discharged into the upper Charles River (Exh. EPEC-8, p. 3-19). In order to assess the impact of the proposed diversion of 1.35 cfs of effluent from the upper Charles River, the Siting Council first examines the reliability of EPEC's analysis of the effect of the proposed diversion on streamflow levels in the upper Charles River. The Siting Council next examines the reliability of EPEC's analysis of the effect of the predicted changes in streamflow levels on water quality in the upper Charles River. The Siting Council then reviews the reliability of EPEC's analysis of the effect of the changes in streamflow and water quality on riverine ecology in the upper Charles River. Finally, the Siting Council determines whether the proposed effluent diversion would have an acceptable impact on waterways.

a. Streamflow

EPEC presented detailed studies of the impact of the proposed effluent diversion on streamflow levels in the upper Charles River (id., pp. 3-57 to 3-73, 4-31 to 4-54). Specifically, EPEC analyzed the impact of the proposed diversion on the frequency and duration of low flow events in the upper Charles River (id.). EPEC defined a low flow condition as any flow below three cfs (id., p. 4-31).

EPEC explained that its low flow analysis focuses on whether streamflow would fall below three cfs for four reasons: (1) three cfs corresponds to the Massachusetts Water Resources Commission ("WRC") minimum streamflow guideline ("MSG") for the upper Charles River basin of 0.21 cubic feet per second per square mile of upland watershed ("cfsm");[117] (2) three cfs represents the minimum MWTP flow (because MWTP flow has fallen below this level only once in the last four years); (3) three cfs is the annual minimum streamflow event, based on historical record, with an average recurrence frequency of once-a-year; and (4) three cfs is a streamflow that appears to have no significant ecological impacts (id.).

EPEC performed three analyses of the impact of the proposed diversion on streamflow levels. First, EPEC presented a flow duration curve, which shows the probability that the MSG of three cfs for the upper Charles River would be exceeded at any point in time, both with and without the proposed facility, based on the history of independent streamflow measurements (Exh. EPEC-8, pp. 3-61, 4-33). Next, EPEC calculated the historical incidence of low flow conditions, which determines the percentage of days, by month, during an historical period of record when flow would have fallen below three cfs if the proposed facility had been operating (id., pp. 3-61 to 3-63). Finally, EPEC correlated streamflow level to water level, using the United States Environmental Protection Agency's ("US EPA") hydrodynamic model DYNHYD, to predict the likely impact of the proposed diversion on water level and velocity (id., pp. 4-38 to 4-42). A brief description of the methodology and results for

117/ EPEC explained that the WRC establishes MSGs through an iterative process of balancing water supply with consumptive and non-consumptive uses, based on input from numerous state and federal agencies (Tr. 4, pp. 119-124). EPEC stated that, pursuant to the Water Management Act, withdrawals may be made which result in flow less than the MSG ten percent of the time during the average year (Exh. EPEC-8, p. 4-34). MDEM's "Hydrologic Analysis and Recommendation for Minimum Streamflow" for the Charles River basin states that:

> The minimum streamflow threshold was tested iteratively to determine a reasonable level while protecting the environmental quality of the basin. The flow of 0.21 cfsm [or three cfs] was found to best balance the instream and out-of-stream needs identified in the planning process (Exh. HO-RR-51, p. iv).

each of these analyses follows.

EPEC explained that the flow duration curve was calculated for Box Pond, which is an impoundment of the Charles River located approximately two miles downstream from the MWTP (id., p. 3-27). EPEC stated that it was able to use watershed area and basin relief information gathered from topographic maps, along with MWTP daily flow data for the period following its 1986 upgrade through the end of 1990, to calculate the flow duration curve at Box Pond (id., pp. 3-66 to 3-73). The flow duration curve shows that flow at Box Pond currently exceeds three cfs 99.7 percent of the time (id., p. 4-32). With the proposed diversion of 1.35 cfs to the EPEC facility, the flow duration curve shows that the percentage of time that flow at Box Pond would exceed three cfs drops to 94 percent (id.). Figure 3 is the flow duration curve at Box Pond, with and without the proposed facility.

EPEC next calculated the historical percentage of low flow days at Box Pond, with and without the proposed diversion to the EPEC facility (id., pp. 3-61 to 3-73, 4-32 to 4-37).[118, 119] EPEC's extrapolation of the historical

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118/ EPEC stated that a calculation of the historical percentage of days below three cfs nearer to the MWTP than Box Pond would yield results similar to those for the calculation at Box Pond (Exh. EPEC-19, p. 6-44).

119/ Due to the lack of historical data on flow levels at Box Pond, EPEC was unable to perform a simple statistical calculation of historical low flow for this location (id., p. 3-61). Instead, EPEC used existing data to calculate the historical percentage of low flow days at Dover gauge, which is a United States Geological Survey ("USGS") gauging station located on the Charles River, downstream of Box Pond (id., p. 3-73). EPEC explained that it then calculated a flow duration curve for Dover, similar to the flow duration curve that it previously had calculated for Box Pond (id.). Finally, EPEC stated that by correlating the flow duration curve for Dover with that for Box Pond, it was able to extrapolate the historical percentage of low flow days at Dover to the historical percentage of low flow days at Box Pond, with and without the proposed facility (id.).

percentage of low flow days at Box Pond shows an increase in the number of low flow days which would have occurred during the period 1960 to 1989 if the proposed facility had been diverting water from the upper Charles River (Exh. HO-RR-58, Table 4.2.1-2, Revised). Specifically, EPEC indicated that, without the proposed facility, low flows would have been recorded at Box Pond for only 0.6 percent of the days in August and 0.4 percent of the days in September (id.). In contrast, with the proposed facility, low flows would have been recorded on 3.4 percent of July days, 22 percent of August days, 21.2 percent of September days, 8.7 percent of October days, and 2.2 percent of November days (id.). EPEC asserted that these results show a conservative, worst-case scenario because they assume maximum effluent consumption of 1.35 cfs at all times, without consideration of seasonal variation in effluent consumption (id., p. 4-45).[120]

Finally, EPEC stated that it used the DYNHYD model to analyze how the proposed diversion of effluent would affect the water level and streamflow rate in the upper Charles River (id., p. 4-38). EPEC stated that it modeled a location on the Charles River between the MWTP and Box Pond (id.). EPEC explained that this location is conservatively representative of impacts along the upper Charles River, and presents a more instructive location for the DYNHYD analysis than Box Pond, because the greater width and lesser slope at Box Pond dampen impacts on water level (id.).

EPEC stated that it used field data collected in September and October, 1990 to calibrate and validate the DYNHYD model for the portion of the river being studied (id.). EPEC explained that, once it has been calibrated and validated,

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120/ EPEC stated that average annual consumption of effluent by the proposed facility, when operating at 100 percent of capacity, would be 1.2 cfs (Tr. 4, p. 153). EPEC further noted that effluent consumption by the proposed facility would increase with ambient temperature (id.).

DYNHYD can be used to predict water level and water velocity under conditions not existing at the time field data was collected (id.). Thus, EPEC indicated that it was able to model water level and water velocity under drought conditions (streamflow of three cfs) with the proposed effluent diversion of 1.35 cfs (id.).

EPEC claimed that the results of the DYNHYD modeling suggest that the water level at the selected location on the Charles River under drought conditions would be approximately one foot above the river bottom, and that with the proposed diversion under drought conditions this level falls to approximately eight inches above the river bottom (id., pp. 4-38 to 4-42). Overall, with the proposed diversion, the water level varies approximately two feet from flood conditions to drought conditions (id., p. 4-40).

Several intervenors raised a number of questions regarding the soundness of EPEC's analysis of the impact of the proposed effluent diversion on streamflow and water levels.

CRWA argued that EPEC inappropriately applied the minimum streamflow threshold of three cfs as an environmental impact assessment tool, when it in fact is a balance between in-stream flow requirements and withdrawal levels based on current and planned uses (CRWA Initial Brief, pp. 10-11). Bellingham similarly argued that the three cfs minimum streamflow threshold may be too low (Bellingham Initial Brief, p. 5). Bellingham cited the Massachusetts Department of Fish and Wildlife ("MDFW") comment letter on EPEC's DEIR, which states that "MDFW ...believes the reliance on WRC's low flow figure of 3.0 cfs to be unreasonable as this flow rate would not adequately protect existing fisheries" (id., Exh. EPEC-8A, p. 2).[121] The record indicates that during the WRC process to

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121/ In its Reply Brief, EPEC asserted that the comments on the DEIR "are hearsay and cannot be used in these adjudicatory hearings to prove the truth of the matter asserted, cannot be relied upon here to rebut the uncontradicted testimony and exhibits in the record, and cannot constitute substantial (footnote continued) calculate the MSG, the MDFW recommended an MSG of 0.5 cfsm, which is equivalent to 7.2 cfs at Box Pond, for the relevant segment of the Charles River (Exhs. HO-RR-51, p. 53, Exh. EPEC-19, p. 4-1).

EPEC addressed the comments on the DEIR in its FEIR (Exh. EPEC-19). In response to the concerns raised by CRWA and Bellingham, and in the MDFW comment letter, regarding the applicability of three cfs as the minimum streamflow guideline, EPEC reasserted that three cfs is a "relevant and protective value for a minimum streamflow" (id., p. 4-36). EPEC further explained that the recommended minimum streamflow guideline of 0.5 cfsm, referenced in the MDFW comment letter, is derived from a United States Fish and Wildlife Service ("USFWS") proposal (id., p. 4-15). That proposal sets forth that the median August streamflow of 0.5 cfsm is the flow which must be maintained year round in order to protect fisheries resources in New England (id.). EPEC stated, however, that the recommended streamflow level of 0.5 cfsm does not take into account differences among river basins, or along different sections of a particular river basin (id.).

EPEC indicated that the WRC MSG of three cfs is specific to the upper Charles River (Exh. EPEC-8, p. 4-31). EPEC further indicated that 0.5 cfsm is greater than the actual median August streamflow for the upper Charles River, so applying the USFWS standard of 0.5 cfsm actually would require flow augmentation (Exh. EPEC-19, p. 4-17). EPEC argued that the MSG resulting from the WRC analysis specific to the upper Charles River is more valid than the basin-wide average number referenced by the MDFW (EPEC Reply Brief, p. 19).

(footnote continued) evidence here to support any finding of the Council" (EPEC Reply Brief, p. 1). EPEC further asserted that "[a]djudicatory hearings at the Council would be reduced to a state of legal chaos if the attempt of Intervenors here to rely on improper 'evidence' is given any weight" (id., p. 2). The Siting Council notes, however, that pursuant to Step 12 of the MOU signed by the Siting Council, MEPA, and EPEC, all comments on EPEC's DEIR are automatically included in the record in this proceeding.

Bellingham also argued that the empirical data gathered by EPEC on the upper Charles River does not fit the DYNHYD-simulated flow very well, which erodes the credibility of DYNHYD study (Bellingham Initial Brief, p. 5).[122] EPEC responded, in its FEIR, that the DYNHYD model, when calibrated, fits the empirical data on water level within two to three inches, which EPEC considers an excellent fit (Exh. EPEC-19, p. 6-47). EPEC further stated that, most importantly, the model accurately simulates both the timing and the amplitude of the average daily fluctuations in river elevation (id.).

CRWA raised the additional concern that the streamflow studies inappropriately focus on Box Pond, rather than on the stretch of river between the MWTP and Box Pond (CRWA Initial Brief, p. 10). CRWA noted that Box Pond, as an impoundment of the Charles River, serves to dampen the flood waves created by the MWTP discharge (id.). EPEC responded in the FEIR that the analysis of the effect of the proposed diversion on water level and velocity focuses on representative river sections between the MWTP and Box Pond, and that flow duration curves for the section of the river between the MWTP and Box Pond would be similar to those which were calculated for Box Pond (Exh. EPEC-19, p. 6-44).

Finally, CRWA stated that the Manning's "n" coefficient (a fitting parameter used to calibrate the DYNHYD model) used by EPEC in its modeling of the impact of the proposed diversion on water level and velocity in the upper Charles River is questionable, and that it may have resulted in an unrealistically low predicted impact on water level (CRWA

122/ The Siting Council notes that this is the same argument raised by MDFW in its comments on the DEIR (Exh. EPEC-8A).

Initial Brief, p. 10).[123] EPEC responded in its FEIR that the Manning's "n" coefficient is not a parameter calculated by EPEC from the input data, but rather is a fitting parameter used to calibrate the model output with observed data (Exh. EPEC-19, pp. 6-48 to 6-49). Thus, EPEC explained that the Manning's "n" coefficient is an empirical parameter whose most important criterion for selection is that it provide the best possible fit between modeled streamflow parameters and observed streamflow parameters (id.). EPEC further stated that the values for "n" used in the analysis correspond to conditions existing in the upper Charles River (id.).

The Siting Council notes that EPEC has provided comprehensive analyses of the impact on streamflow in the upper Charles River which would result from the proposed diversion of effluent to the EPEC facility. Further, EPEC has provided clear documentation of the methodologies employed in these analyses.

Specifically, EPEC has supported its use of three cfs as the definition of low flow, or drought conditions. EPEC has demonstrated that three cfs is the flow level for the upper Charles River with a once-a-year recurrence frequency. This provides a more appropriate definition of low flow than the alternative MSG suggested by the intervenors, which is not specific to the upper Charles River.[124] In addition, the Siting Council notes that the alternative MSG currently is not

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123 EPEC argued in its Reply Brief that CRWA's statement is an impermissible testimonial assertion of opinion without any support in the record (EPEC Reply Brief, p. 12). The Siting Council concurs that no evidence was submitted during evidentiary hearings which suggests that the Manning's "n" coefficient used by EPEC in its DYNHYD analysis is questionable. Nevertheless, because the issue is raised in the comment letters on the DEIR which are included in the record in this proceeding, and because EPEC responded to this concern in its FEIR, the Siting Council includes an evaluation of the Manning's "n" coefficient in its analysis.

124/ The adequacy of EPEC's proposal to cease its diversion of effluent when flow in the upper Charles River falls below three cfs to protect the resources of the upper Charles River is addressed in Section III.E.3.d, below.

being met.

EPEC has provided detailed descriptions of its methodology for calculating flow duration curves at Box Pond and Dover, and for extrapolating the historical frequency and duration of low flow events which would have occurred at Box Pond with the proposed diversion. Moreover, EPEC has demonstrated that its use of Box Pond for calculating flow duration curves and historical low flow is representative of the impact of the proposed diversion on the frequency and duration of low flow events in the section of the Charles River between the MWTP and Box Pond.

Similarly, EPEC has provided a detailed description of its application of the DYNHYD model to calculate the impact of the proposed diversion on water level and velocity. Further, the record does not contain any evidence to contradict EPEC's assertion that the fit of empirical to modeled parameters is excellent, and that its Manning's "n" coefficient is reasonable. More importantly, the record demonstrates that the model accurately predicts the average daily fluctuations in water level and velocity.

While the Siting Council recognizes that no methodology would be able to predict the future with absolute accuracy, the methodologies described by EPEC provide reasonable assurance that the predicted impacts of the proposed diversion on the frequency and duration of low flow events, and on water level and velocity, are representative of what is likely to occur. Accordingly, the Siting Council finds that EPEC's analysis of the impact on streamflow of the proposed diversion of 1.35 cfs of effluent from the upper Charles River to the proposed project at either the primary site or the alternative site is reliable.

b. <u>Water Quality</u>

i. <u>Background</u>

EPEC analyzed the impact of the predicted reduction in streamflow levels, due to the diversion of effluent to the proposed facility, on water quality in the upper Charles River from a point one-half mile upstream of the MWTP to the Box Pond dam (Exh. EPEC-8, pp. 3-23 to 3-57, 4-55 to 4-64). EPEC stated that periods of low river flow potentially could degrade water quality in the upper Charles River (id., p. 3-57). EPEC asserted that reductions in streamflow slow water movement, thereby increasing "water residence time" and raising water temperature (id.). EPEC further noted that lower streamflow can result in reduced water turbulance, which in turn diminishes the amount of oxygen entering the water through reaeration (id.). EPEC explained that the dissolved oxygen ("DO") concentration in a river is one of the most important indicators of the river's ability to assimilate waste and to support aquatic life (id., p. 3-43). Thus, EPEC examined the impact of the predicted reduction in streamflow level on three water quality parameters: DO concentration, temperature and the amount and concentration of pollutants loaded into the stream (id.).

EPEC indicated that it used the US EPA model "QUAL2E" to measure the impact of the proposed reduction in streamflow level on water quality (id., p. 3-43). EPEC stated that QUAL2E is capable of describing the rate of change of DO levels in a river by modeling the interaction between the most important determinants of DO levels in the river (id., pp. 3-43 to 3-44). EPEC further stated that QUAL2E is widely used for waste allocation studies and other conventional pollution determinations, and that it can simulate up to 15 water quality constituents (id.). EPEC further explained that QUAL2E is a steady-state model with respect to stream hydraulics, in that it assumes all sources which contribute to streamflow are constant (id., p. 3-47).

EPEC explained that it used field data for the upper Charles River gathered in September and October 1990, along with historical data from August 1988, to calibrate and verify the QUAL2E model (id., pp. 3-53 to 3-57).[125] EPEC stated that it

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125/ EPEC stated that it used the historical data in addition to its own field data in order to capture summer as well as autumn conditions (Tr. 4, p. 87).

was then able to use QUAL2E to model the changes in DO concentrations and water temperature which would result from the proposed diversion of effluent under the conditions represented by the calibration and verification data sets, as well as under several worst-case scenarios (id., pp. 4-56 to 4-57).[126]

ii. Dissolved Oxygen Concentrations

EPEC stated that its September and October, 1990 field studies showed that the DO concentrations in the upper Charles River were quite low upstream from the MWTP, then increased with the addition of higher-DO effluent at the MWTP, then decreased again below the MWTP, and finally, increased at Box Pond (id., p. 3-47). EPEC stated that the results of its modeling suggest that DO concentrations in the upper Charles River are not very sensitive to changes in streamflow (id., p. 4-56).

EPEC stated that the DO concentrations at Box Pond dam would experience a maximum drop of 0.7 parts per million of DO due to the proposed diversion, relative to the concentrations associated with the calibration and verification data sets (id.). EPEC asserted that this drop is not considered significant (id.). EPEC further explained that the most realistic worst-case scenario examined doubling the biochemical oxygen demand in the segment of the river being studied with a 75 percent reduction in oxygen-producing algae concentrations (id.). EPEC stated that DO concentrations drop substantially under this scenario (id.). However, EPEC stated that when streamflow was reduced under this scenario, DO concentrations actually increased (id.). EPEC concluded that DO concentrations in the upper Charles River are more sensitive to photosynthesis than to factors which vary with streamflow, such as reaeration and biochemical oxygen demand (id.).

126/ EPEC explained that it developed worst-case scenarios to predict the impact of low flow in combination with the increased biochemical oxygen demand and decreased oxygen production of decaying organic matter, as occurs in autumn (Exh. EPEC-8, p. 4-56).

iii. Water Temperature

EPEC stated that it also used QUAL2E to predict the impact of the proposed effluent diversion on water temperature in the upper Charles River (id., p. 4-59). EPEC asserted that, in order to determine the maximum impact on temperature which would result from the proposed effluent diversion, it focused on the Box Pond dam (id.). Specifically, EPEC presented the impact on temperature of the proposed diversion under three scenarios: (1) the September 1990 day used for QUAL2E calibration; (2) a hypothetical hot June day (which combines extended daylight hours, solar radiation and high air temperature); and (3) the highest water temperature in the August 1988 data set (id.). EPEC stated that temperature showed little change as flow was varied under each of these scenarios (id.). In particular, EPEC indicated that as streamflow was decreased by 1.35 cfs (the amount of the diversion to the proposed facility) from 4.35 cfs to 3.0 cfs (the MSG for the upper Charles River), water temperature increased by a maximum of 1.0 degree Fahrenheit (id.). EPEC concluded that changes in the rate of MWTP discharge, such as those which would result from the proposed effluent diversion, would not have a significant impact on water temperature in the upper Charles River (id.).[127]

iv. Pollutant Concentrations

EPEC evaluated potential changes in pollutant concentrations in the upper Charles River due to the proposed

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127/ EPEC noted that the temperature of the cooling tower wastewater which is returned to the MWTP would be reduced prior to discharge into the upper Charles River through a combination of: (1) travel time between the proposed facility and the MWTP; (2) dilution with the MWTP waste stream; and (3) the residence time through the MWTP (Exhs. EPEC-8, p. 4-62, EPEC-19, p. 6-68).

effluent diversion (id., pp. 4-59 to 4-64).[128] Specifically, EPEC analyzed (1) the concentration of pollutants discharged by the MWTP (which would include wastewater from EPEC's cooling tower after it was returned to the MWTP and treated), and (2) the impact of increased residence time on nutrient uptake levels in Box Pond (id.).

In order to determine the impact of the proposed effluent diversion on the concentration of pollutants discharged by the MWTP, EPEC explained that it met with the Milford Sewer Commission and the engineers who designed the MWTP (Exh. HO-RR-53). EPEC asserted that the wastewater from the proposed facility would not add any new pollutants to the MWTP effluent, but that the addition of the wastewater from the proposed facility to the MWTP effluent stream would increase concentrations of some of the existing components in the effluent (Exh. EPEC-8, p. 4-62).[129] EPEC noted that this increase in concentration would be due to the impact on the facility's wastewater of evaporation in the cooling towers. EPEC stated that the MWTP currently discharges effluent into the Charles River pursuant to a National Pollutant Discharge Elimination System ("NPDES") permit, which sets forth water quality standards for ammonia, phosphorus, biochemical oxygen demand, total suspended solids and settleable solids (id., p. 4-59 to 4-64). EPEC explained that the MWTP currently removes these pollutants from the Town of Milford sewage in

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128/ EPEC included the nutrients phosphorus and nitrogen in its analysis of pollutant concentrations (Exh. EPEC-8, pp. 4-59 to 4-64). EPEC indicated that plant community composition can change significantly as a result of (1) increased nutrient concentrations in the water, or (2) increased water residence time, which allows plants to absorb a greater quantity of the nutrients present in the water (id.).

129/ EPEC initially stated that the proposed facility would increase copper loading in the MWTP effluent stream due to leaching from the cooling tower's copper condenser (Exh. EPEC-8, p. 4-62). However, EPEC stated that it subsequently changed its design from a copper to a stainless steel condenser, which would eliminate copper loading (Tr. 4, p. 32).

order to comply with the NPDES permit (id.). EPEC asserted that the concentration of each of these pollutants, except phosphorus, would be lower in the EPEC wastewater than the concentrations in the Town of Milford sewage currently treated at the MWTP (id., Exh. HO-RR-53). Thus, EPEC stated that these pollutants would be removed from the EPEC wastewater at the MWTP, and would not interfere with the normal operations of the MWTP (id.). With regard to phosphorus, EPEC asserted that the concentration of phosphorus in the EPEC wastewater would be approximately equal to that of the concentration of phosphorous in the Town of Milford sewage, such that it similarly would not affect MWTP operations (id.).

EPEC identified two additional pollutants which would be concentrated in the EPEC wastewater, but which are not removed by the MWTP: metals and nitrates (Exh. EPEC-8, p. 4-59). EPEC stated that the concentration of metals, including zinc, and nitrates in the effluent discharged by the MWTP would increase by 40 percent when the EPEC wastewater is combined with the Town of Milford sewage (id., p. 4-62). With regard to metals, EPEC explained that all metals, except zinc, are consistently below detection limits in the MWTP effluent, and that the 40 percent increase caused by the EPEC wastewater was not likely to bring those metals above detection limits (id.). Accordingly, EPEC stated that the 40 percent increase in the concentration of metals, except zinc, would not have a significant impact on water quality in the upper Charles River (id.). Further, EPEC asserted that, during the only recorded occurrence of zinc concentration in the MWTP effluent above detection limits, the concentration of zinc in the Charles River upstream from the MWTP was 34 percent higher than that in the MWTP effluent, and that the downstream concentration was 450 percent higher than that of the MWTP effluent (id.). Thus, EPEC concluded that the 40 percent increase in the concentration of zinc in the MWTP effluent which would result from the EPEC wastewater is insignificant with respect to instream conditions in the upper Charles River (id.). With regard to nitrates, EPEC stated that the 40 percent increase in concentration in the MWTP effluent is not significant because it is phosphorus, rather than nitrogen, which limits algal and macrophyte growth in the upper Charles River. As such, EPEC asserted that the increased concentration of nitrates would not result in increased plant growth (Tr. 4, p. 68, Tr. 5, pp. 33-34). Finally, EPEC stated that it would monitor the wastewater stream from the proposed facility, and that if pollutant concentrations in the wastewater stream exceed water quality standards, EPEC would modify its operations to ensure compliance with those standards (id., p. 4-62).

As noted above, EPEC also evaluated the potential increase in nutrient uptake levels in Box Pond due to increased water residence time (id., pp. 4-55, 4-64). EPEC indicated that it first examined the relationship between streamflow and water residence time in Box Pond (id.). EPEC stated that it then compared the predicted water residence time with nutrient uptake rates (id.).

EPEC stated that its streamflow analysis demonstrates that water levels in Box Pond are not predicted to change under the range of flows studied so the volume of water in Box Pond is expected to remain relatively constant (id., p. 4-64). EPEC stated that its analysis indicates that Box Pond's flushing rate, or the period of time during which all the water in the pond is exchanged, would increase somewhat due to the lower flows which would result from the proposed effluent diversion (id.). Specifically, EPEC asserted that the flushing rate at average flow would increase from 12 days to 13 days, and the flushing rate at low flow would increase from 53 days to 77 days (id.).

EPEC next stated that it employed QUAL2E to determine the nutrient uptake rate in Box Pond for phosphorus (id.). EPEC indicated that phosphorus uptake in Box Pond occurs at an average rate of 17 milligrams per liter ("mg/L") per day, even though incoming phosphorus concentrations consistently are below

0.25 mg/L per day (id.).[130] Thus, EPEC concluded that phosphorus is the limiting nutrient in Box Pond and that it is rapidly absorbed, such that the increased flushing rate which would result from the proposed effluent diversion would not affect the amount of phosphorus which is absorbed in Box Pond (id.).

v. Arguments of the Parties

Intervenors in the proceeding raised a number of issues regarding the adequacy of EPEC's analysis of the impact of the proposed effluent diversion on water quality in the upper Charles River.

Bellingham argued that QUAL2E is an inappropriate model for the segment of the upper Charles River studied by EPEC because QUAL2E is a steady-state model which does not adequately account for diurnal fluctuations in effluent discharge from the MWTP (Bellingham Initial Brief, p. 5). EPEC responded that it adequately compensated for the inability of QUAL2E to model dynamic flows by applying the model to worst-case conditions, which conservatively assume constant low flow conditions, rather than fluctuating flow (Exh. EPEC-19, p. 6-57). EPEC also noted that fluctuations in DO concentrations in the upper Charles River are attributable to photosynthesis and respiration, rather than fluctuations in MWTP flow, and that QUAL2E does incorporate this daily cycle of photosynthesis and respiration (Exh. EPEC-8, p. 3-57).

CRWA argued that EPEC's analysis is inadequate because it does not establish time-of-travel versus flow profiles for the segment of the river being studied, and that the proposed facility's impact on the ability of the river to assimilate pollutants therefore is unknown (CRWA Initial Brief, p. 11). EPEC responded that the record does include time-of-travel data,

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130/ EPEC stated that rooted plants in the study area receive phosphorus from sediments, as well as from the water column (Tr. 5, p. 34).

and that QUAL2E enabled EPEC to determine the impact of the proposed facility's operation on the ability of the river to assimilate pollutants (EPEC Reply Brief, p. 14). EPEC further responded that the proposed facility would not cause flows to drop below the MSG for the upper Charles River, and that the MSG is designed to preserve the river's ability to assimilate pollutants (id.).

CRWA also argued that EPEC did not perform an adequate assessment of the impact of operation of the proposed facility on the ability of the MWTP to conform with current and future NPDES permits and water quality standards in the Charles River (CRWA Initial Brief, p. 3). In particular, CRWA stated that EPEC did not adequately consider the impacts of increased concentrations of nitrates, metals, copper and chlorine (id., p. 11). Similarly, Bellingham stated that EPEC did not address the impact of reduced streamflows on downstream NPDES permits and water quality (Bellingham Initial Brief, p. 10).

EPEC responded that the record does include consideration of the ability of the MWTP to continue to comply with its NPDES permit (EPEC Reply Brief, p. 14). EPEC cited the discussion in the DEIR of the concentration of pollutants entering and exiting the MWTP which would result from operation of the proposed facility (id.). EPEC further responded in its FEIR that the engineers for the MWTP have determined that MWTP operations would not be affected by the concentration of pollutants in wastewater from the proposed facility, and that the presence of sodium hypochlorite[131] in the wastewater similarly would not affect operations at the MWTP (Exh. EPEC-19, pp. 6-64 to 6-67). Finally, EPEC reasserted that a study of the impacts of copper leaching is not necessary because the cooling tower has been

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131/ EPEC asserted that it replaced the chlorine included in its original proposal for use in cooling tower treatment with sodium hypochlorite in response to safety concerns related to the storage of chlorine on site (Exhs. EPEC-8, p. 2-22, EPEC-19, pp. 2-20 to 2-21).

redesigned to replace the copper condenser with a stainless steel condenser (EPEC Reply Brief, p. 15).

vi. Analysis

EPEC has presented comprehensive analyses of the impact of the predicted reduction in streamflow on water quality in the upper Charles River. EPEC has provided clear documentation of the methodologies and inputs used to analyze the impact of the proposed project on water quality. Specifically, EPEC has documented the appropriateness of the QUAL2E model for the upper Charles River and has clearly explained its selection of inputs for the model. The methodologies described by EPEC provide reasonable assurance that the predicted impacts of the operation of the proposed facility on (1) DO concentrations, (2) temperature, and (3) pollutant concentrations and loadings in the upper Charles River are representative of what is most likely to occur. Accordingly, the Siting Council finds that EPEC's analysis of the impact on water quality in the upper Charles River of the predicted reduction in streamflow, due to the diversion of effluent to the proposed facility, at either the primary site or the alternative site is reliable.[132]

The Siting Council notes that EPEC has demonstrated that its facility would not affect the MWTP's ability to comply with its current NPDES permit. However, future NPDES permits may be more restrictive, and may regulate constituents such as metals and nitrates, which are not regulated under the current permit. The Siting Council fully expects that EPEC would operate in a manner which would not affect the ability of the MWTP to comply with future NPDES permits. Accordingly, the Siting Council ORDERS EPEC to provide the Siting Council with any modifications to the current MWTP NPDES permit along with an analysis of how EPEC would ensure that operation of the proposed facility does

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132/ The acceptability of the predicted impacts on water quality is addressed in Section III.E.3.d, below.

not restrict the ability of the MWTP to comply with any such permit.[133]

c. Riverine Ecology

i. Background

EPEC analyzed the impact of the predicted changes in streamflow levels and water quality, due to the proposed effluent diversion, on riverine ecology in the upper Charles River (Exhs. EPEC-8, pp. 3-93 to 3-153, 4-70 to 4-110, EPEC-19, pp. 4-27 to 4-31, 6-87 to 6-97). Specifically, EPEC studied the impacts of the proposed diversion on four biological communities: (1) aquatic macrophytes; (2) phytoplankton; (3) aquatic macroinvertebrates; and (4) fish (id.).

EPEC explained that it applied the results from long-term, intensive ecosystem studies for other rivers to understand the likely impact of the proposed effluent diversion on riverine ecology in the upper Charles River (id., pp. 4-27 to 4-28). Thus, EPEC claimed that it was able to use the qualitative field surveys it conducted to obtain meaningful results without conducting exhaustive, and disruptive, sampling (id., p. 4-28).

EPEC explained that the conceptual framework for its application of other studies to the upper Charles River and its analysis of likely impacts included consideration of: (1) ecosystem interrelationships; (2) guild groupings; and (3) control mechanisms (Exh. EPEC-19, pp. 4-27 to 4-28). EPEC explained that the concept of ecosystem interrelationships requires that an environmental disturbance be understood in the context of the importance of the structural and functional characteristics which are being disturbed to the ecosystem as a whole (id., p. 4-27). EPEC further explained that guild theory

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133/ The Siting Council recognizes the jurisdiction of the US EPA and MDEP over the NPDES permit process. This ORDER in no way changes EPEC's obligation to comply with US EPA and MDEP standards.

recognizes that organisms can be grouped according to similarities in resource utilization, such that if environmental disturbances affect a resource, and the impact on one species within the guild that uses that resource is determined, then the impact on other species within the guild can be determined (id., pp. 4-27 to 4-28). Finally, EPEC explained that its conceptual framework recognizes that stream ecosystems can be influenced by stochastic, or unpredictable, mechanisms as well as by deterministic mechanisms, such as resource competition (id., p. 4-28).

EPEC stated that headwater streams, such as the upper Charles River, are demonstrated to be primarily stochastic systems where overall species abundance is highly variable (id.). EPEC stated that it used the qualitative field surveys it conducted to characterize predominant habitat guilds in the upper Charles River, which it then calibrated to well-studied headwater systems (id.). EPEC asserted that it then applied ecosystem theories of structure and function to evaluate potential impacts of the proposed diversion on the upper Charles River (id.).

ii. Aquatic Macrophytes

The first biological community examined by EPEC was aquatic macrophytes, or aquatic vegetation (id., pp. 3-106 to 3-110, 4-71 to 4-76). EPEC explained that macrophytes perform several functions within a water body, including: (1) cycling nutrients through the aquatic system by converting inorganic nutrients to organic nutrients; (2) providing shelter, refuge and substrate for aquatic organisms; and (3) affecting DO levels through photosynthetic-respiratory activity (id., pp. 3-106, 4-71). EPEC stated that it developed criteria for assessing potential impacts to macrophytes based upon their role in the aquatic ecosystem, such that it focused on the potential loss of habitat associated with the reduced streamflow (id., p. 4-71). Specifically, EPEC stated that it would consider impacts to aquatic macrophytes significant if the proposed effluent diversion resulted in: (1) substantial changes in the size of macrophyte beds or biomass, or (2) appreciable shifts in species composition of macrophyte communities (id.).

EPEC identified four environmental factors which govern the species composition and size of macrophyte communities: (1) hydrologic factors; (2) water quality including temperature, light and DO concentration; (3) water chemistry; and (4) biotic interactions (id., pp. 7-72 to 4-76). In order to examine the impact of the proposed effluent diversion on the identified environmental parameters, EPEC stated that it conducted field surveys of macrophyte communities in the upper Charles River, reviewed previous studies of the upper Charles River for comparison with its own field survey results, and reviewed literature on longer-term studies of macrophytes in other riverine systems (id., pp. 3-106 to 3-110, 4-71 to 4-76).

EPEC's field studies identified dense beds of submerged vegetation throughout the study area (id., p. 3-106). EPEC indicated that total bottom coverage varies from a low of 20 percent at one riverine sampling station to a high of 90 percent at Box Pond, with the remaining riverine sampling stations averaging approximately 60 percent total bottom cover (id., pp. 3-106 to 3-108). EPEC also asserted that there are abundant macrophyte communities in Box Pond, a condition typical of waters with shallow depth and high nutrient concentrations (id., p. 3-110).[134]

In addition to relying on its own field studies of aquatic macrophytes in Box Pond, EPEC cited studies conducted by the Massachusetts Department of Environmental Quality

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134/ EPEC cited several factors which contribute to the abundance of macrophytes in Box Pond: the high levels of nutrients in the Box Pond sediments (which are utilized by rooted plants), as well as in the water column; the shallow depth of the water, which allows light to penetrate the entire water column; the slow pond flushing rate, which allows plants more time to utilize nutrients in the water column; the generally slow velocity of the river; and the suitability of the habitat (Exh. EPEC-8, p. 3-110).

Engineering (now MDEP) in July 1985 and June, July and August 1988 and by Gale Associates in 1987-1988 and 1990 of aquatic macrophytes in Box Pond (id., pp. 3-109 to 3-110).

With regard to hydrological factors, EPEC referenced studies of macrophytes which have demonstrated that hydrological factors, such as streamflow levels, do have some impact on aquatic macrophytes (id., p. 4-72). In fact, EPEC claimed that certain species propagate more rapidly during, and immediately following, drought conditions due to the improved ability of light to reach the river bottom (id.). However, EPEC cited an additional study which demonstrates that aquatic macrophytes are adaptable to changes in water level (id.). Thus, EPEC stated that the proposed diversion is not likely to create a significant impact on macrophytes due to hydrological factors (id.). Specifically, EPEC asserted that the existing macrophyte beds, which are absent from the outer edges of the river bottom, already have adapted to frequent low flow events in the upper Charles River (id.). EPEC further maintained that, because the proposed diversion would not cause flows to fall below their current minimum level, the predicted increase in low flow frequency and duration should not result in significant changes in macrophyte biomass and species composition (id.).

With regard to water quality, EPEC cited studies which show that certain species of aquatic macrophytes are affected by light intensity and temperature (id., pp. 4-71 to 4-73). EPEC asserted, however, that light intensity in the upper Charles River is limited by seasonal factors and overhanging vegetation (id.). EPEC claimed that the proposed diversion would not affect the light intensity along the river because it would not affect the seasonal influences or the amount of overhead vegetation along the upper Charles River (id.). Further, EPEC claimed that the predicted worst-case temperature variation of one degree Fahrenheit due to the proposed diversion would not be sufficient to result in significant impacts on the existing aquatic macrophytes (id.). Finally, EPEC noted that changes in DO concentrations in the upper Charles River due to the proposed effluent diversion are predicted to be indistinguishable from existing concentrations in most other segments of the river, and that the predicted changes in the remaining segment of the river are insignificant in comparison to current temporal variations in DO concentrations (id.).[135]

In evaluating the impact on aquatic macrophytes of changes in water chemistry due to the proposed diversion, EPEC noted that nitrogen and phosphorus are known to be limiting to macrophyte communities (id., p. 4-74). EPEC cited studies which it claims have demonstrated that certain species of macrophytes receive the majority of their nutrients from sediments, rather than from the water column (id.). In addition, EPEC cited a study which claims that changes in the amount of phosphorus loading in the water column can result in shifts between high-growing and low-growing aquatic macrophytes (id.). In comparing this information with the predicted impact of the water chemistry changes due to the proposed diversion, EPEC concluded that no significant changes would occur in the biomass or species composition of aquatic macrophyte beds in the upper Charles River (id.). Specifically, EPEC asserted that it does not expect the proposed diversion to change most water chemistry constituents, with the exception of a small increase in nitrates (id.). However, EPEC stated that the additional nitrates would be rapidly attenuated by physical and biological processes occurring in the river, such as denitrification, so that the changes would not be of a magnitude which would affect aquatic macrophytes (id.).

The final environmental factor affecting aquatic macrophytes examined by EPEC was biotic interactions (id., p. 4-75). With regard to the biotic interactions of aquatic macrophytes, EPEC cited studies which document the interaction between macrophytes and other communities, including

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135/ EPEC noted that macrophytes actually cause significant diurnal swings in DO concentrations through photosynthesis and respiration (Exh. EPEC-8, pp. 4-71 to 4-73).

phytoplankton, or algae, zooplankton and fish (id.). Specifically, EPEC claimed that a decrease in the standing crop of macrophytes can result in an increase in the phytoplankton population, and that macrophytes provide shelter and habitat for zooplankton and fish, as well as a food source for fish (id.). EPEC asserted that, because no appreciable changes in macrophyte biomass or community structure are predicted to result from the proposed diversion, no changes in the biotic interactions of macrophytes are expected (id.).

iii. Phytoplankton (Algae)

EPEC also studied phytoplankton (Exh. EPEC-8, pp. 3-110 to 3-124, 4-76 to 4-82). EPEC explained that phytoplankton are important within the aquatic system because they produce oxygen through photosynthesis, and they provide a food source for other organisms (id., p. 4-76). EPEC asserted that it is important to maintain a balanced phytoplankton population (id.). Specifically, EPEC stated that it would consider changes to phytoplankton significant if those changes exacerbated nuisance algal blooms (id.).[136] EPEC identified four environmental factors which can exacerbate nuisance algal blooms: (1) stream hydrology; (2) physical characteristics such as light intensity,[137] turbidity and nutrient availability; (3) concentrations of DO and other constituents; and (4) biotic interactions among species which compete with phytoplankton for resources and among species which consume phytoplankton (id.).

136/ EPEC described algal blooms as occurrences of dense colonies of phytoplankton which (1) usually form near the water surface, (2) decrease the aesthetic value of the water, (3) impart unpleasant taste or color to the water, (4) release substances toxic to aquatic life, and (5) decrease light penetration to the water column (Exh. EPEC-8, p. 4-77).

137/ It is the Siting Council's understanding that light intensity includes factors which affect the amount of light reaching the water surface (e.g., shade from vegetation) as well as factors affecting the penetration of light through the water (e.g., suspended sediments in the water).

In order to examine the impact of the proposed effluent diversion on the environmental factors which can contribute to nuisance algal blooms, EPEC stated that it conducted field surveys of phytoplankton populations in the upper Charles River, reviewed previous studies of the upper Charles River for comparison with its own field survey results and reviewed literature on longer-term studies of phytoplankton in other water bodies (id., pp. 3-110 to 3-124, 4-76 to 4-82).

EPEC's field studies reveal the presence of phytoplankton populations in the upper Charles River (id., pp. 3-110 to 3-124). EPEC's studies suggest that phytoplankton density generally is greater in Box Pond than in the riverine sections of the study area, with the exception of the section of the river nearest the MWTP discharge point (id.). EPEC attributed this variation in density to differences in water quality along the study area, including the differences in the concentrations of nitrogen and phosphorus and the ability of light to penetrate the water column (id., p. 3-124). EPEC claimed that phytoplankton communities in Box Pond were, however, much less diverse than those in the rest of the study area (id.). EPEC asserted that the overall level of phytoplankton diversity observed along the study area is indicative of an ecosystem exposed to low to moderate stresses (id.).

EPEC stated that no recent studies of phytoplankton communities have been conducted in the riverine sections of the study area, although studies have been conducted in Box Pond (id., pp. 3-117, 3-122). EPEC cited studies of Box Pond conducted by the Massachusetts Department of Environmental Quality Engineering (now MDEP) in July 1985 and in June, July and August 1988 (id., p. 3-122). EPEC further cited a 1987-1988 study of Box Pond conducted by Gale Associates, which claims that the phytoplankton community composition in Box Pond varies significantly throughout the year (id.). EPEC compared the results of the previous studies of phytoplankton at Box Pond to its own survey results (id.). EPEC stated that the dominant species found in the recent EPEC field survey were not dominant in DEP's August, 1988 study, and were not found at all during the year-long, 1987-1988 study conducted by Gale Associates (id.). EPEC further noted that the phytoplankton density recorded in its own study was higher than that which was recorded in the previous studies (id.). Finally, EPEC indicated that the phytoplankton biomass (which measures the productivity occurring in the water column) recorded in 1985 was significantly higher than that recorded in subsequent studies, including EPEC's own field surveys (id.). EPEC attributed this change in phytoplankton biomass to the 1987 upgrade of the MWTP, which reduced the nutrient loading into the water column (id.).

EPEC claimed that little information is available regarding the response of phytoplankton to changes in stream hydrology (id., p. 4-77). EPEC cited a study of the Middle Snake River in Oregon, which was unable to draw any conclusions regarding the effects of varying stream flows on the density or diversity of phytoplankton (id.). EPEC also maintained that little or no information is available regarding the response of phytoplankton to changes in DO concentrations (id., p. 4-78). EPEC explained that most studies have focused on the ability of phytoplankton to cause changes in DO concentrations through photosynthetic-respiratory activity (id.). However, EPEC was able to cite studies of the indirect effects to phytoplankton of changes in light intensity, turbidity and nutrient availability (id., p. 4-77).

EPEC claimed that the proposed effluent diversion would not exacerbate nuisance algal blooms because: the minimum streamflow which would occur due to the proposed effluent diversion is within the range of flows currently experienced in the upper Charles River; the proposed effluent diversion is not predicted to cause changes in light intensity or turbidity; and the proposed effluent diversion would cause only a small absolute increase in the concentration of nitrogen, which is one of the limiting nutrients for phytoplankton (id.). Finally, EPEC concluded that, because substantial changes in phytoplankton populations are not predicted to result from the proposed effluent diversion, secondary impacts on biotic interactions are not predicted (id.).

iv. Macroinvertebrates

EPEC next examined the impact of the proposed effluent diversion on aquatic macroinvertebrates (id., pp. 3-125 to 3-144, 4-82 to 4-87). EPEC stated that macroinvertebrates, which include species such as leeches, snails, and sludge worms, constitute the largest number of organisms in freshwater habitats (id., p. 3-125). EPEC asserted that macroinvertebrates function in the aquatic system as nutrient cyclers and as a food source for other aquatic organisms (id., p. 4-82). EPEC identified three conditions which would represent a significant impact to macroinvertebrates: (1) significant loss of habitat; (2) substantial shifts in the existing community structure; and (3) appreciable reductions in the standing crop (id.).

EPEC stated that the results of its sampling in the upper Charles River indicate significant variation in the diversity and density of various types of macroinvertebrates at different sampling stations (id., p. 3-141).[138] Nevertheless, EPEC indicated that it was able to identify certain common trends (id.). First, EPEC noted that the diversity of types of macroinvertebrates collected by all three sampling methods was lowest in Box Pond, and highest at the furthest upstream sampling stations (id.). EPEC attributed the low diversity of types of macroinvertebrates found at Box Pond to the historically low concentrations of DO in the hypolimnion, or

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138/ EPEC stated that the differing habitat for each community of macroinvertebrates required different sampling methods (Exh. EPEC-8, pp. 3-125 to 3-136). The three communities of macroinvertebrates identified by EPEC are: meroplanktonic macroinvertebrates (organisms which spend a portion of their life stages as plankton, drifting in the water column); benthic epifauna (organisms which live exclusively on rock or stone surfaces on the river bottom); and benthic infauna (organisms which live on or within the river bottom substrates) (id.).

lower layer of water, at that location (id.). EPEC further noted that the types of macroinvertebrates common to all sampling stations included species which other studies have shown to be indicative of a stressed system with conditions generally unfavorable to most other organisms (id.).

EPEC asserted that the abundance and composition of macroinvertebrates can be influenced by three factors: (1) hydrological factors; (2) water quality; and (3) biotic interactions (id., pp. 4-83 to 4-87).

With regard to hydrological changes, EPEC cited studies documenting extreme variation among different macroinvertebrate species' tolerance for fluctuating stream flows (id.). EPEC further cited studies which argue that the timing and duration of stream flow fluctuations affects their impact on macroinvertebrates, with daily variations having a stronger impact than a continual low-flow event (id.).

EPEC analyzed the impact of the predicted changes in hydrology on three communities of macroinvertebrates identified in the upper Charles River (id.). EPEC asserted that no significant impacts were predicted among the meroplankton, which colonize aquatic macrophytes located in the main channel of the stream, since the proposed effluent diversion is not predicted to cause stream flows to drop below current low flow levels (id.). EPEC similarly claimed that no significant impacts would occur to benthic epifauna because the species which were found to be predominant in the study area can actively escape dewatered areas by moving to the middle of the channel as streamflows decrease (id.). In addition, EPEC cited a study which points out that benthic epifauna in streams such as the upper Charles River have their highest biomass concentrated in the midstream areas, where they are less susceptible to changes in flow than they would be if concentrated along the outer edges of the stream (id.). EPEC also asserted that the predicted changes in stream hydrology would not significantly affect benthic infauna because the species identified in the upper Charles River have documented avoidance behavior and tolerance to streamflow variation (id.).

With regard to water quality, while EPEC identified temperature as an important influence on the density and diversity of macroinvertebrate species, EPEC also asserted that the predicted worst-case temperature change (a one degree Fahrenheit increase) is insufficient to result in any significant impacts to macroinvertebrate populations (id., p. 4-86). EPEC concluded that, because no significant changes in the macroinvertebrate population are predicted to occur as a result of the proposed diversion, no secondary impacts on biotic interactions are expected to occur (id.).

v. Fish

The final biological community examined by EPEC was the fisheries community (id., pp. 3-144 to 3-153, 4-87 to 4-110; Exh. EPEC-19, pp. 4-31 to 4-37). EPEC asserted that fish play a major role in aquatic systems, both as a food source for other wildlife and as predators since fish-eating species control the populations of forage fish, which in turn affects the standing crop and species diversity of plankton (Exh. EPEC-8, p. 4-87). EPEC stated that it developed criteria for assessing fisheries community characteristics based on their significance for maintaining a balanced, indigenous population in the upper Charles River (id.). Specifically, EPEC stated that it would consider impacts to fish significant if the proposed effluent diversion resulted in: substantial changes in the indigenous community biomass and standing crop; significant loss of potential habitat; or impediments to fish passage (id.).

EPEC stated that it conducted a fisheries survey of the upper Charles River in September, 1990, as well as studies of the types of habitat available for resident fish species (id.). Overall, EPEC concluded that the results of its survey indicate a low diversity of fish species in the upper Charles River (id., p. 3-152). However, EPEC claimed that the survey demonstrates the adaptability of the identified species to a variety of habitats, given the differences among the locations where they were observed during the survey (id.).

EPEC stated that limited information has been published regarding the fisheries existing in the upper Charles River (id.). However, EPEC cited fisheries surveys conducted by the MDFW in 1982 and by an independent consultant in 1990, both of which documented results similar to those gathered by EPEC in its field surveys (id.).

To analyze the impact of the proposed effluent diversion on the fisheries community in the upper Charles River, EPEC stated that it conducted two types of analysis (id., pp. 4-88 to 4-110). First, EPEC explained that it employed the USFWS Instream Flow Incremental Methodology ("IFIM") to quantify usable fisheries habitat as a function of streamflow in the upper Charles River (id., pp. 4-89 to 4-91, Exh. EPEC-19, pp. 6-89 to 6-94). The second analysis presented by EPEC estimated the potential impact on the fisheries community of changes in hydrology, water quality and biotic interactions by applying the results of studies which have been conducted in other areas of the United States to the upper Charles River (Exh. EPEC-8, pp. 4-91 to 4-109).

EPEC's witness, Dr. Mary Best, testified that EPEC's IFIM study calculated available usable habitat in the upper Charles River by correlating field data on streamflow, bottom substrate type, bottom area, and the locations in which organisms were observed with empirical data on the habitat requirements of the fish and other aquatic organisms which are known to inhabit the stream (Tr. 5, pp. 38-39, 55).[139] EPEC explained that, for the purpose of the IFIM study, it selected two representative study areas in the upper Charles River and two resident fish species for which empirical data was available (Exh. EPEC-8, pp. 4-89 to 4-91). EPEC cautioned that, although its IFIM study

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139/ EPEC defined total usable habitat as all of the area that an organism can move into in a stream (Tr. 5, p. 45). EPEC explained that total usable habitat includes marginal, or suboptimal, habitat as well as preferred habitat (id.).

provides useful information for assessing the potential worst-case impacts from the proposed effluent diversion on potentially sensitive indicator species, it should not be used in isolation to provide a minimum streamflow recommendation (Exh. EPEC-19, pp. 6-89 to 6-90). In addition, EPEC identified certain limitations on the applicability of the IFIM study to the upper Charles River including: (1) the lack of empirical habitat suitability information for many of the resident species, (2) the short-term fluctuation in streamflows associated with the MWTP discharge pattern; and (3) the relatively small change in streamflow (1.35 cfs) being analyzed (id., pp. 4-29, 6-90).[140]

As the basis for its IFIM study, EPEC explained that it gathered field data on streamflow, bottom substrate type, bottom area and the location of resident species in September, 1990 (id., p. 4-89; Tr. 5, pp. 38-39, 55). EPEC indicated that it then used the set of velocity data included in its IFIM field data to calibrate two hydraulic computer programs which simulate changes in usable habitat as a function of one-cfs changes in flow (Exh. EPEC-8, p. 4-89). EPEC's IFIM study analyzed the two resident fish species for which habitat suitability information is available: largemouth bass and white sucker (id., pp. 4-89 to 4-98). Specifically, EPEC stated that its IFIM study included all life stages (spawning, fry, juvenile and adult) for largemouth bass and juvenile white sucker (id.). EPEC indicated that it assessed impacts on habitat for each species and lifestage based upon the percentage change in usable habitat area with the predicted 1.35 cfs decrease in flow, as determined

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140/ EPEC noted that the size of streamflow changes in the upper Charles River due to the proposed effluent diversion is several orders of magnitude smaller than those encountered in most IFIM studies, which focus on major hydroelectric or irrigation projects (Exh. EPEC-19, p. 4-29).

by the IFIM study (id., p. 4-90).[141]

EPEC described the results of its IFIM study as showing that statistically significant reductions in habitat would occur only at one of the two upper Charles River study areas (id., p. 4-91). EPEC stated that a reduction from six cfs (the measured level at that location) to four cfs would result in a 37 percent reduction in adult largemouth bass habitat and a 30 percent reduction in largemouth bass fry habitat (id., p. 4-91).[142] EPEC further noted that its IFIM study predicts that a significant adverse impact on fish habitat would occur as a result of the proposed 1.35 cfs diversion only if flows were to fall below 3 cfs, which, according to EPEC's mitigation strategy, they would not (id.).

EPEC stated that it next turned to the results of studies which have been performed in other areas of the United States with regard to the impact of streamflow on fish due to changes in hydrology, water quality and biotic interactions (id.).

EPEC stated that quantitative studies of the response of warmwater fisheries to changes in stream hydrology are rare because most studies have been conducted in cold water streams in the western United States (id.). Nevertheless, EPEC cited studies of both cold water and warmwater streams which it claimed document a number of factors relevant to the likely response of resident fish species to the predicted reduction in streamflow (id., pp. 4-99 to 4-106). Specifically, EPEC asserted that all of the species of fish identified in the upper Charles River are somewhat flexible in their habitat

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141/ EPEC noted that its IFIM study presents a conservative analysis because the marginal habitat which is included in the definition of usable habitat generally occupies the outer edges of the stream, which is the first area to be affected by a reduction in flow (Tr. 5, p. 45).

142/ EPEC noted that average model error was considered to be 30 percent due to the field measurements of a rapidly fluctuating flow; changes in habitat of less than 30 percent were not considered statistically significant (Exh. EPEC-8, p. 4-91).

requirements (id., p. 4-101). EPEC further indicated that most of the observed species prefer sluggish, calm pools within riverine systems (id.). EPEC stated that the upper Charles River contains significant numbers of such pools, which would provide adequate refuge where adult fish could congregate during low flows (id.). EPEC further noted that several of the identified fish species have been shown to be intimately associated with aquatic macrophytes throughout their life-cycles and that no significant shifts in macrophyte density or composition are predicted to result from the proposed diversion (id.). Finally, EPEC stated that all of the identified fish species are spring spawners, such that spawning should not be affected by the predicted low flows of late summer (id.).

To assess the impacts of the predicted changes in water quality on resident fish species, EPEC focused on predicted changes in temperature and DO (id., pp. 4-107 to 4-108).

With regard to temperature, EPEC cited studies which claim that most warmwater fish species are able to exist within a wide temperature range, and that fish can acclimate to gradual changes in temperature within that range (id., p. 4-107). EPEC further noted that the ability of fish to tolerate a range of temperatures varies during different life stages, with juveniles and adults able to tolerate a wider range than embryos (id.). EPEC asserted that the predicted maximum temperature increase of one degree Fahrenheit in August due to the proposed effluent diversion is within the range tolerated by all the adult species of fish observed in the upper Charles River, and that higher August temperatures should not affect spring spawning (id., p. 4-108). Thus, EPEC concluded that changes in temperature due to the proposed effluent diversion should not have an adverse impact on the resident fisheries community (id.).

With regard to predicted changes in DO concentrations, EPEC noted studies which indicate that the responses of fish to changes in DO are similar to their responses to changes in temperature (id., p. 4-107). Specifically, given a sufficient period for acclimation, fish can adapt to a range of levels of

DO concentrations (id.). EPEC concluded that fish species in the upper Charles River already are adapted to variations in DO concentrations from the current shifts in DO concentrations caused by phytoplankton and macrophyte photosynthesis and respiration (id.). Further, EPEC noted that the predicted worst-case decrease in DO concentrations due to the proposed effluent diversion would not result in DO concentrations below those already experienced in the upper Charles River (id.).

Finally, EPEC examined the possible changes in biotic interactions due to the proposed effluent diversion (id., p. 4-109). Although EPEC cited studies of the cascading effects of fish predation on the aquatic food web, EPEC asserted that no impacts on biotic interactions in the upper Charles River were anticipated because no changes were predicted in the adult fish species resident in the river (id.).

vi. Arguments of the Parties

CRWA and Bellingham raised a number of questions regarding EPEC's analysis of the impacts of the proposed effluent diversion on riverine ecology in the upper Charles River. Specifically, CRWA and Bellingham argued that EPEC has failed to demonstrate that there would be no significant impact on fisheries and aquatic life (CRWA Initial Brief, pp. 12-13, Bellingham Initial Brief, p. 5). CRWA cited the predicted reduction in habitat for adult largemouth bass of 37 percent and for largemouth bass fry of 30 percent (CRWA Initial Brief, p. 12). CRWA further criticized the methodology used by EPEC in its IFIM study, including its selection of indicator species and its failure to account for the varying needs of fish and macroinvertebrates during different life stages (id.).

EPEC argued that the predicted reductions in largemouth bass habitat result from a decrease in flow greater than that which would result from the proposed effluent diversion (EPEC Reply Brief, p. 15). EPEC asserted that the IFIM results are for a two-cfs reduction in flow, while the proposed diversion would result in a 1.35-cfs reduction in flow (EPEC Reply Brief,

p. 15). Further, EPEC argued that its IFIM analysis as described in the record in this proceeding was conducted appropriately (id.). EPEC similarly asserted that its focus on juvenile and adult life stages is appropriate because these are the life stages which correspond with late summer periods of low flow (id., p. 16).

vii. Analysis

EPEC has clearly described its analysis of the likely impact of the proposed effluent diversion on the riverine ecology associated with the upper Charles River. EPEC carefully documented the results of its own and previous studies of the upper Charles River. EPEC acknowledged the limitations of its IFIM study of available habitat, and correctly cautioned that the results of its IFIM study cannot be used in isolation to predict the impact on available habitat which would result from the proposed effluent diversion. Recognizing the lack of data available on the upper Charles River, EPEC appropriately included studies of other riverine systems in its analysis. EPEC also provided a clear description of the conceptual framework it employed to apply the results of those studies to the upper Charles River. In sum, EPEC has provided a clear, well-documented analysis of the impact of the proposed effluent diversion on riverine ecology in the upper Charles River.

Nevertheless, the reliability of EPEC's analysis of the impact of the proposed effluent diversion on riverine ecology is somewhat limited by the lack of (1) a long-term study of the riverine ecology presently associated with the upper Charles River, and (2) studies of the impact of increasing the duration and frequency of low flow events in warmwater rivers such as the upper Charles River. While EPEC has appropriately used all available data to predict the impact of the proposed effluent diversion on riverine ecology, the identified data limitations reduce the reliability of EPEC's analysis.

The Siting Council notes that the MDEP's Division of Water Pollution Control currently is negotiating the terms of a resource monitoring, assessment and mitigation plan with EPEC which will require an impact assessment of the proposed effluent diversion on the upper Charles River prior to and following start-up of the proposed facility, as well as require EPEC to implement additional mitigation measures in the event that negative environmental impacts to the upper Charles River due to operation of the proposed facility are identified (Exh. EPEC-19A).[143] Implementation of this resource monitoring, assessment and mitigation plan will provide assurance to the Siting Council that the conclusion of EPEC's analysis -- that operation of the proposed facility with the identified effluent-use mitigation strategy would not have a negative impact on riverine ecology -- is accurate. Thus, the Siting Council ORDERS EPEC to (1) develop, in conjunction with MDEP, a resource monitoring, assessment and mitigation plan, (2) provide the Siting Council with a copy of the final resource monitoring, assessment and mitigation plan, and (3) provide the Siting Council with copies of any reports to MDEP required under the plan at the time such reports are provided to MDEP or more frequently as directed by the Siting Council.

The resource monitoring, assessment and mitigation plan shall include, but not be limited to: (1) an assessment of impacts to water resources;[144] (2) mitigation of any negative environmental impacts identified by MDEP to have been caused by

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143/ The Siting Council notes that the resource monitoring, assessment and mitigation plan will be subject to a 30-day MEPA public comment process before becoming final (Exh. EPEC-19C).

144/ The assessment of impacts to water resources should include, but not be limited to: (1) wetlands extent and type; (2) wetland soils characteristics; (3) groundwater levels and quality; (4) surface water quantity, flow and quality; and (5) aquatic biota. Monitoring data for the assessment of impacts to water resources should include: (1) physical/chemical parameters such as pH, total suspended solids, organic and inorganic constituents, DO and other data required by the NPDES permit at the MWTP; (2) instream and whole effluent toxicity data; (3) plant and animal species diversity; and (4) other necessary data.

the proposed effluent diversion from the upper Charles River; and (3) compliance with the minimum streamflow for the upper Charles River determined by MDEP to be necessary for the protection of aquatic life.[145] Further, the monitoring plan developed as part of the resource monitoring, assessment and mitigation plan shall be in place in sufficient time to allow collection of one full year of data prior to initiating the proposed effluent diversion.[146]

Accordingly, based on compliance with the above ORDER, the Siting Council finds that EPEC's analysis of the impact on riverine ecology of the proposed effluent diversion from the upper Charles River to the proposed facility at either the primary site or the alternative site is reliable.

d. Conclusion on Waterways

The Siting Council has found that EPEC's analyses of the impact on streamflow and water quality of the proposed diversion of 1.35 cfs of effluent from the upper Charles River to the proposed project at either the primary site or the alternative

145/ The Siting Council's consideration of the proposed facility assumes implementation of EPEC's stated effluent-use mitigation strategy. The Siting Council notes that this strategy could change as a result of negotiation or implementation of the resource monitoring, assessment and mitigation plan. The Siting Council further notes that a change in EPEC's effluent-use mitigation strategy could lead to changes in the cost or reliability of the proposed facility. In Section IV, below, the Siting Council ORDERS EPEC to notify the Siting Council of any changes other than minor variations to the proposal so that the Siting Council may decide whether to inquire further into that issue. In accordance with this ORDER, EPEC shall notify the Siting Council if proposed changes in the effluent-use mitigation strategy would result in other than minor variations in the cost or reliability of the proposed facility.

146/ The Siting Council notes that the proposed facility currently is scheduled to begin operations on January 1, 1993 (Tr. 7, p. 45). Failure to implement the monitoring plan by January 1, 1992 necessarily would delay operation of the proposed facility until one full year of data has been collected.

site are reliable. The Siting Council also has found that, upon compliance by EPEC with the ORDER set forth in Section III.E.3.c.vii, above, EPEC's analysis of the impact on riverine ecology of the proposed effluent diversion from the upper Charles River to the proposed project at either the primary site or the alternative site is reliable. Here, the Siting Council considers the acceptability of the predicted impacts on the upper Charles River.

EPEC has demonstrated that, through its effluent-use mitigation strategy of ceasing effluent diversions when such diversions would cause streamflow in the upper Charles River to fall below three cfs, operation of the proposed project would increase the frequency and duration of low-flow events, without causing streamflow in the upper Charles River to drop below existing low-flow levels. EPEC also has demonstrated that the increased duration and frequency of low-flow events would not cause significant changes in three important water quality parameters: DO concentrations, temperature and pollutant loadings. Further, EPEC has presented well-documented analyses which predict that the proposed effluent diversion will not have a negative impact on riverine ecology in the upper Charles River. Compliance by EPEC with the ORDER set forth in Section III.E.3.c.vii, above, further ensures that operation of the proposed project would not result in a negative impact to the riverine ecology associated with the upper Charles River.

Accordingly, the Siting Council finds that the proposed project, at either the primary site or the alternative site, would have an acceptable impact on waterways upon compliance by EPEC with the ORDER set forth in Section III.E.3.c.vii, above.[147]

147/ The Siting Council notes that this finding is based upon the comprehensive studies performed by EPEC of the impact of increased frequency and duration of low flow events on streamflow, water quality and riverine ecology in the upper Charles River, rather than upon the determination by the WRC (footnote continued)

4. Wetlands

In this section, the Siting Council evaluates the impact of construction and operation of the proposed facility (including the generating facility, effluent line from the MWTP, electric transmission interconnect, sewer line and 100-foot natural gas pipeline) on wetlands at the primary and alternative sites.

a. Primary Site

i. Generating Facility

EPEC stated that there are no wetlands associated with the originally identified primary site for the generating facility, which has been previously altered and developed as a tractor-trailer parking lot and a warehouse and literature distribution center (Exhs. EPEC-8, p. 3-85, EPEC-19, p. 2-2; Tr. 5, p. 73). However, during the course of the proceeding, EPEC indicated that it acquired an additional parcel of land, Lot 2, to the east of the initially identified primary site where it intends to relocate the tractor-trailer parking lot currently located on the primary site (Exh. HO-RR-83). EPEC documented the presence of wetlands associated with the Charles River on the eastern boundary of Lot 2 (id.). EPEC claimed that the parking lot would be located in the southern portion of Lot 2, where no disturbance to wetlands would result from construction of the parking lot (id.).

Although no wetlands are located on the portion of the primary site where the generating facility would be located, EPEC acknowledged that an increase in runoff and sedimentation

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(footnote continued) that three cfs is the appropriate MSG for the upper Charles River. The record contains substantial documentation that the WRC MSG was not established to provide a protective environmental baseline, such that it should not be used, without additional analysis, to determine the streamflow level at which EPEC should reduce its effluent diversion. The Siting Council commends the comprehensive analysis performed by EPEC, and notes that it would not have been able to make a similar finding without this thorough documentation.

could result from construction of the proposed facility (Exh. EPEC-8, p. 4-69). EPEC asserted that the potential for an increase in runoff and sedimentation would be mitigated by: (1) the installation of stacked haybales and silt fences around the perimeter of the construction area; (2) the planned use of the existing detention pond for control of runoff and sedimentation; and (3) the relatively flat topographic nature of the primary site, which limits the need for grading activities (id.). EPEC further noted that the stormwater management plan for the primary site would be subject to an NPDES permit and that while the amount of runoff discharged from the site would not be changed significantly by the proposed facility, EPEC would employ mitigation measures at the point of discharge to reduce any potential for erosion off-site (id., p. 4-70).

EPEC has established that no wetlands are present on the initially identified primary site or the portion of Lot 2 which would be disturbed by construction of the proposed facility. EPEC also has identified mitigation measures which will limit runoff and erosion during construction and operation of the proposed facility. Accordingly, the Siting Council finds that construction of the proposed generating facility at the primary site, with the mitigation measures described by EPEC, would have an acceptable impact on wetlands.

Although CCAP, CRWA and Bellingham did not express concerns regarding potential wetlands impacts on the proposed generating facility site, they did raise the argument that the proposed effluent diversion would result in an illegal alteration to wetlands as defined by the Massachusetts Wetlands Protection Act ("WPA") (CRWA Initial Brief, p. 13, Bellingham Initial Brief, p. 6).

EPEC responded that the record evidence does not support the arguments raised by CCAP, CRWA and Bellingham (EPEC Reply Brief, p. 16). Specifically, EPEC indicated that it analyzed the potential impact of the effluent diversion from the upper Charles River to the proposed facility on wetland areas along the river, as defined in accordance with the WPA (id., pp. 4-112 to 4-116, Exh. EPEC-19, pp. 6-97 to 6-102). EPEC concluded that because the wetland systems already have adapted to the existing lowflows, which the proposed diversion would not reduce, the jurisdictional interests of the WPA would be protected (Exh. EPEC-8, pp. 4-113 to 4-116). Specifically, EPEC claims that the proposed effluent diversion would not alter or impair the following wetland classifications subject to the WPA: land under water bodies and waterways, bordering vegetated wetlands, river banks, or bordering land subject to flooding (id.).

The Siting Council notes that it is not within our purview to apply or predict the application of the WPA.[148] However, we recognize that a finding by an affected conservation commission or the MDEP that the proposed effluent diversion constitutes an alteration to a wetland as defined by the WPA ultimately could alter the cost, environmental and reliability characteristics of the proposed facility. Accordingly, the Siting Council ORDERS EPEC to submit to the Siting Council a determination from the affected conservation commissions and/or from MDEP of the applicability of the WPA to the wetlands impact resulting from the proposed effluent diversion.

ii. Effluent Line

EPEC indicated that the proposed facility would require construction of a 36-inch diameter pipeline to carry effluent from the MWTP to the proposed facility for use as cooling water (Exh. EPEC-8, pp. 2-11 to 2-15, 3-92). EPEC provided a map of its preferred route for the effluent line which indicates that it would be slightly less than one mile in length, and would travel eastward from the primary site boundary for approximately 1,000 feet, across the Conrail railroad tracks and the Charles River, where it would turn south, traveling approximately

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148/ In Section III.E.3, above, the Siting Council comprehensively reviews the impacts of the proposed effluent diversion on the upper Charles River and associated riverine ecosystem.

3,500 feet, and then turn west, cross the Charles River a second time, and enter the MWTP property (id., p. 3-89). EPEC stated that its preferred effluent line route is parallel to a planned Town of Milford sewer intercept for all but the first 1,000 feet of its length, and that EPEC intends to coordinate construction of the effluent line with that of the sewer intercept in order to minimize wetlands impacts (Tr. 6, p. 151). EPEC maintained that the combined sewer intercept/effluent line right-of-way would be 30 feet wide: 20 feet for the sewer line intercept and an additional 10 feet for the effluent line (Exh. HO-RR-64). EPEC further claimed that construction along this 30-foot right-of-way would require alteration of 32,250 square feet of bordering vegetated wetland (of which 2,750 square feet would be filled and 3,320 square feet would be replicated) and 1,950 square feet of land under water bodies and waterways (id.). EPEC claimed that the potential for successful regeneration of wetland plant species in these areas is highly probable (Exh. EPEC-19, p. 3-7). EPEC further documented mitigation measures which would be employed in the wetland crossings, such as the use of clay migration barriers to reduce sediment migration (Exh. HO-RR-62).

EPEC identified two alternatives to its preferred effluent line route: (1) alternative A, which is parallel to the railroad track to the east of the primary site, and which would require alteration of 49,500 square feet of wetlands; and (2) alternative B, which would travel westward from the primary site to avoid the Charles River crossings, but which nevertheless would require alteration of 43,950 square feet of wetlands (id., Exh. HO-RR-65).

EPEC claimed that the Charles River crossings required by the preferred route and alternative A do not present any engineering difficulties, and that the environmental difficulties were not considered severe by EPEC (Tr. 6, pp. 148-150).

The Siting Council notes that EPEC's preferred effluent line route would require alteration of wetland areas. The

Siting Council further notes that the alternative effluent line routes identified during the proceeding would result in even greater impacts to wetlands. However, the Siting Council commends EPEC's attempts to identify alternative effluent line routes, as well as EPEC's commitment to synchronize construction of the effluent line with construction of the sewer intercept to minimize wetlands impacts. Accordingly, based on the foregoing, the Siting Council finds that EPEC's preferred effluent line route to the primary site, if constructed simultaneously with the sewer intercept, would have an acceptable impact on wetlands. The Siting Council further finds that EPEC's preferred effluent line route is preferable to alternative A and alternative B with respect to wetlands impacts.

iii. Electric Transmission Line

EPEC indicated that operation of the proposed facility at the primary site would require construction of two electric transmission lines, each approximately 1,000 feet in length, with one transmission line along each side of the Conrail railroad track as it travels from the northern edge of the site boundary to an existing NEPCo electric transmission line (Exhs. EPEC-8, p. 3-7, EPEC-19, p. 2-19, HO-RR-79; Tr. 6, p. 162-163). EPEC demonstrated that construction of the proposed electric transmission lines would require clearing a 150-foot right-of-way of all tall-growing vegetation, although low-growing species would not be removed (Exh. HO-E-23). EPEC stated that the only wetland area crossed by the proposed electric transmission lines would be the Godfrey Brook and its associated wetlands, which have a maximum width of 175 feet and a minimum width of 125 feet (Tr. 5, p. 84). EPEC's witness, Mr. Damiano, noted that, by siting the transmission lines parallel to the railroad track, the electric transmission lines would cross Godfrey Brook and its associated wetlands at their narrowest point, such that poles could be located on each side of the wetland area, instead of within it (id.).

EPEC has demonstrated that the two transmission lines from the primary site to the NEPCo transmission line would be constructed in a manner that minimizes impacts on wetlands. However, in order to ensure that wetlands impacts are minimized, the Siting Council ORDERS EPEC to locate the transmission line poles outside the Godfrey Brook wetland area, and to locate any access roads in a manner which avoids wetland alteration.

Accordingly, the Siting Council finds that construction of the proposed electric transmission lines for the primary site, based on compliance with the above ORDER, would have an acceptable impact on wetlands.

iv. Sewer Line

EPEC stated that construction of the proposed facility at the primary site would require construction of a sewer line from the facility to the planned Town of Milford sewer intercept (Exh. EPEC-8, p. 3-92). EPEC noted that the sewer line would be sited parallel to the effluent line as it exits the primary site boundary, crosses the Conrail railroad tracks and the Charles River, and joins the sewer intercept right-of-way (id.). Thus, EPEC indicated that the wetlands impacts for the sewer line, which would cross 260 linear feet of wetlands, are identical to those for the first 1,000 feet of the effluent line (id.).

Accordingly, the Siting Council finds that the proposed sewer line for the primary site, if constructed simultaneously with the effluent line and with any MDEP-mandated route modifications, would have an acceptable impact on wetlands.

v. Natural Gas Pipeline

EPEC indicated that delivery of natural gas for the proposed facility at the primary site would require construction of (1) a 100-foot natural gas pipeline extending from the existing Algonquin pipeline (which for the most part parallels the railroad right-of-way to the east of the primary site) to the proposed project, and (2) a new meter station at the southern edge of the primary site (Exh. HO-PV-34.1).[149] The record demonstrates that no wetlands will be affected by construction of the 100-foot natural gas interconnect or the new meter station (Exh. EPEC-8, p. 4-110).

Accordingly, the Siting Council finds that the proposed natural gas pipeline and meter station at the primary site would have an acceptable impact on wetlands.[150]

b. Alternative Site

i. Generating Facility

EPEC documented the presence of wetland areas on approximately ten acres of the 48-acre alternative site (Exh. EPEC-8, p. 5-9). EPEC claimed that the facility layout has been sited in such a manner that construction at the alternative site would avoid construction in or near on-site wetlands (id., Exh. HO-RR-63). EPEC indicated that the impacts to wetland areas associated with construction of the proposed facility at the alternative site would be similar to the impacts associated with construction at the primary site (Exh. EPEC-8, p. 7-5). Specifically, EPEC indicated that a stormwater runoff system would be developed for the alternative site which would

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149/ EPEC further noted that construction of approximately 3.1 miles of pipeline looping (placement of a new pipeline parallel to an existing pipeline) will be necessary along the existing Algonquin pipeline in order to deliver natural gas to the proposed project, whether located at the primary site or the alternative site (Exh. HO-PV-34.1). The necessary looping will be constructed by Algonquin, subject to certification by FERC. EPEC indicated that the existing Algonquin pipeline traverses extensive wetlands, such that the necessary looping is likely to have significant wetland impacts (Tr. 5, p. 116).

150/ The Siting Council makes no finding regarding the impact on wetlands or the necessary mitigation for the pipeline looping proposed by Algonquin in order to supply natural gas to the proposed project. The Siting Council recognizes FERC jurisdiction over the Algonquin construction, and has intervened in FERC docket CP91-1983-000 and will submit comments to FERC recommending specialized construction techniques to minimize construction impacts in wetland areas.

function in a manner similar to the runoff system proposed for the primary site (id.). EPEC further noted that the impact of the proposed effluent diversion on wetland areas along the upper Charles River would be identical for both sites because the same amount of effluent would be diverted from the same point in the river (id.).

Accordingly, the Siting Council finds that the construction of the proposed generating facility at the alternative site, with the mitigation measures described by EPEC, would have an acceptable impact on wetlands.

ii. Effluent Line

EPEC stated that construction of the proposed project at the alternative site would require construction of a 36-inch diameter effluent pipeline to carry effluent from the MWTP to the proposed facility for use as cooling water (Exh. EPEC-8, p. 3-211). EPEC noted that the effluent line to the alternative site would be constructed within a "utility corridor" including effluent, electric, sewer and natural gas lines (id., p. 3-207).[151] EPEC demonstrated that the utility corridor would extend in a southwesterly direction from the alternative site to the location where the effluent and sewer lines from the primary site would join the Town of Milford sewer intercept right-of-way (id., pp. 3-211, 3-89). From this point, the effluent line route for the alternative site follows the same route to the MWTP as the effluent line route for the primary site (id.).

EPEC acknowledged that the utility corridor traverses approximately 1,150 linear feet of bordering vegetated wetlands

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151/ EPEC indicated that in determining the route for the utility corridor, it followed existing utility rights-of-way to the greatest extent possible to minimize additional clearing and access road construction (Tr. 6, p. 157). The Siting Council notes that the utility corridor includes a combination of existing utility rights-of-way and virgin right-of-way and that the wetlands are predominantly along the virgin right-of-way (Exh. EPEC-8, pp. 3-209 to 3-217).

between the alternative site and the junction with the Town of Milford sewer intercept right-of-way (id., pp. 3-209 to 3-217). EPEC noted that from the junction with the Town of Milford sewer intercept right-of-way, the wetlands impacts associated with construction of the effluent line to the alternative site would be identical to those associated with construction of the effluent line to the primary site (id.). Thus, EPEC maintained that construction along this segment could be synchronized with construction of the Town of Milford sewer intercept (id.). EPEC identified mitigation measures which it would employ to minimize wetlands impacts along the utility corridor similar to those which it described for construction in wetland areas along the effluent route to the primary site (id., pp. 5-9 to 5-10). EPEC further claimed that the potential for successful regeneration of wetland plant species following construction is highly probable (id.).

The Siting Council finds that, with appropriate mitigation measures and simultaneous construction with the Town of Milford sewer intercept for the common portions of the route, the effluent line route for the alternative site would have an acceptable impact on wetlands. The Siting Council further commends EPEC's use of a utility corridor to reduce the total amount of wetlands disturbed by construction of each utility line.

iii. Electric Transmission Line

EPEC stated that operation of the proposed facility at the alternative site would require construction of an electric transmission line 2,300 feet in length (id., p. 3-211). EPEC further stated that the electric transmission line would be sited entirely within the utility corridor from the alternative site (id.). Finally, EPEC noted that the electric transmission line could be located in such a manner that it would not require alteration of any wetland areas (id., pp. 3-211, 5-9).

Accordingly, the Siting Council finds that construction of the proposed electric transmission line for the alternative site would have an acceptable impact on wetlands.

iv. Sewer Line

EPEC indicated that the sewer line from the alternative site would follow the same route as the effluent line from that site (id., p. 3-211). Thus, the proposed sewer line would cross approximately 1,150 linear feet of wetlands, and the impacts to wetland areas would be identical to those associated with the effluent line along that portion of the utility corridor (id.).

The Siting Council finds that construction of the sewer line for the alternative site, with appropriate mitigation measures, would have an acceptable impact on wetlands.

iv. Natural Gas Pipeline

EPEC indicated that locating the proposed facility at the alternative site would require construction of a natural gas pipeline to interconnect with the existing Algonquin natural gas pipeline located southwest of the alternative site (id., p. 3-211). EPEC identified its preferred route for the natural gas pipeline to the alternative site during the course of the proceeding (Tr. 6, p. 157). Specifically, EPEC indicated that the natural gas pipeline would follow the proposed utility corridor to the point where the corridor joins the Town of Milford sewer intercept right-of-way, where the pipeline route would turn west and cross the Charles River to reach the Algonquin pipeline (id., Tr. 5, p. 111-112). EPEC stated that the natural gas pipeline to the alternative site would cross approximately 1,400 linear feet of wetlands (id., pp. 3-92, 3-211).

The Siting Council finds that, with appropriate mitigation measures, the natural gas pipeline to the alternative site would have an acceptable impact on wetlands.

c. Conclusion

The Siting Council has found that, with appropriate mitigation measures and compliance with the above ORDERS, construction of the generating facility, effluent line, electric transmission line, sewer line and natural gas pipeline would have an acceptable impact on wetlands at either the primary site or the alternative site. The Siting Council notes that the proposed generating facility and electric transmission line could be sited in a manner which avoids direct impacts to wetlands at either the primary site or the alternative site. The Siting Council further notes that construction of the effluent line, sewer line and natural gas pipeline to the alternative site would cross significantly more wetland areas than the comparable lines to the primary site.[152] Specifically, the effluent line to the alternative site crosses 1,150 additional linear feet of wetlands, the sewer line crosses approximately 890 additional linear feet of wetlands, and the natural gas pipeline crosses approximately 1,400 additional linear feet of wetlands.

Accordingly, the Siting Council finds the primary site is preferable to the alternative site with respect to wetlands.

5. Air Quality

a. Stack Emissions

EPEC claimed that its decision to use natural gas as the exclusive fuel for its proposed facility and to employ advanced control technologies ensures that the plant stack emissions will be "the lowest of virtually any plant in New England and that the impacts on air quality will be the absolute minimum possible" (Exh. CCAP-E-13(2)).[153] EPEC further stated that it

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152/ Although the Siting Council has made no finding regarding the wetlands impacts of the natural gas pipeline looping to be constructed by Algonquin, the record indicates that the wetlands impacts associated with this construction would be identical for the primary and alternative sites.

153/ EPEC further claimed that the proposed project would provide Massachusetts and the New England region with immediate, quantifiable environmental benefits in the form of reduced air emissions as the result of displacing the emissions of a mix of existing generation facilities in the NEPOOL dispatch order (EPEC Initial Brief, pp. II-26 to II-27). The Siting Council examines the air quality benefits associated with the proposed project's displacement of other generating facilities in Section II.A.4, above.

would use Best Available Control Technology ("BACT") or Lowest Achievable Emission Rate ("LAER") technology to reduce facility emissions in accordance with federal and state regulations (Exh. EPEC-19, p. 2-18). Nevertheless, EPEC acknowledged that the proposed project would emit: (1) NO_x; (2) SO_2; (3) CO; (4) VOCs;[154] (5) particulate matter ("PM"); (6) ammonia; and (7) CO_2 (Exhs. EPEC-8, p. 4-9, HO-E-13). EPEC noted that emissions of each of these substances, with the exception of CO_2, are governed by federal and state air quality regulations (id.).

In the following sections, the Siting Council first reviews the applicable state and federal regulations governing pollutant emission levels and concentration levels, and then evaluates EPEC's ability to comply with those standards and to ensure that the proposed facility would have an acceptable impact on air quality.

i. Applicable Regulations

EPEC explained that the federal Clean Air Act mandated that the US EPA promulgate New Source Performance Standards ("NSPS") which regulate emissions of NO_x and SO_2 for gas turbines (Exh. EPEC-8, p. 4-6). EPEC explained that NSPS reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction, taking into account the cost, non-air-quality health and environmental impacts and energy requirements of that technology (id.). EPEC indicated that Massachusetts similarly requires implementation of BACT for NO_x, SO_2, total suspended solids ("TSP"), PM with a diameter of ten micrometers or less ("PM_{10}"), CO, lead, VOCs and ammonia (id., p. 4-8).

In addition to the requirement that the US EPA establish

154/ EPEC indicated that VOCs are the precursors to ozone (Exh. EPEC-8, p. 4-8).

NSPS, EPEC noted that the federal Clean Air Act mandated the implementation of National Ambient Air Quality Standards ("NAAQS") to regulate six criteria pollutants: (1) SO_2; (2) PM_{10}; (3) NO_x; (4) CO; (5) photochemical oxidants as ozone ("O_3"); and (6) lead (Exh. EPEC-8, pp. 4-1 to 4-5).[155] EPEC stated that an area which is in compliance with NAAQS is classified as an "attainment" area on a pollutant-by-pollutant basis (id., p. 4-2). EPEC noted that Milford is in an attainment area for all criteria pollutants with the exception of O_3 (id.).

EPEC further explained that a significant new source of a criteria pollutant located in a NAAQS attainment area for that pollutant must document the combined impact of the new source, other nearby major sources and ambient background concentrations of that pollutant through a dispersion modeling analysis (id.).[156] EPEC noted that a significant new source of a criteria pollutant in or near a NAAQS non-attainment area for that pollutant must control emission of the pollutant so as to eliminate the significant impact or acquire applicable emission offset limits (id.).

ii. Predicted Impacts

(A) Primary Site

EPEC predicted the emissions of criteria pollutants and resulting ambient concentrations of those pollutants due to operation of the proposed facility at the primary site

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155/ EPEC indicated that Massachusetts has established the Massachusetts Ambient Air Quality Standards ("MAAQS"), which are the same as the NAAQS, except that MAAQS regulates total suspended solids ("TSP") rather than PM_{10} (Exh. EPEC-8, pp. 4-1 to 4-2). EPEC further indicated that the US EPA has delegated responsibility implementing NSPS and NAAQS regulations in Massachusetts to the MDEP (id., pp. 4-1, 4-7).

156/ EPEC indicated that NAAQS establishes significant impact levels ("SILs") for criteria pollutants which determine whether the emissions from a new or modified source are classified as significant (Exh. EPEC-8, pp. 4-1 to 4-4).

(Exhs. EPEC-8, pp. 4-1 to 4-30, EPEC-19, pp. 3-1 to 3-3, 6-14 to 6-32, HO-RR-89).

With respect to NSPS emissions regulations, EPEC claimed that the proposed facility's emissions of both NO_x and SO_2 would be well below NSPS emissions limits (Exh. EPEC-8, pp. 4-6 to 4-7). Specifically, EPEC stated that its proposed use of steam injection and SCR would reduce NO_x emissions to 9 parts per million volume ("ppmv") on a dry basis, corrected to 15 percent oxygen (id.). EPEC noted that the maximum allowed under NSPS is 100 ppmv on a dry basis, corrected to 15 percent oxygen (id.). EPEC also noted that the only source of sulfur in natural gas is that added as odorant, which results in SO_2 emissions well below NSPS emissions limits (Exh. EPEC-8, p. 4-11).

In accordance with NAAQS and MAAQS, EPEC performed a dispersion modeling analysis to predict the SO_2, CO, NO_x and PM concentrations which would result from operation of the proposed facility at the primary site, combined with ambient concentrations (Exhs. EPEC-19, pp. 3-1 to 3-3, HO-RR-89). Specifically, EPEC indicated that it first performed a screening level analysis using two models (1) the Industrial Source Complex Short-Term ("ISCST") model, and (2) the US EPA's Level I complex terrain screening model, known as "Valley" (Exh. EPEC-8, pp. 4-19 to 4-20).

EPEC stated that its ISCST and Valley screening level analyses predicted peak concentrations of SO_2 and PM well below their corresponding SILs (Exh. EPEC-19, p. 6-25).[157] However, EPEC indicated that the ISCST screening analysis predicted peak NO_x and PM concentrations above their corresponding SILs (id.). Thus, EPEC explained that it performed a more refined analysis using the ISCST model in

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157/ EPEC's modeling predicts SO_2 concentrations which range from two percent to 50 percent of SILs, and CO concentrations which range from two percent to 66 percent of SILs, depending upon the averaging period used (one hour, three hour, eight hour, 24 hour or annual) (Exh. EPEC-19, p. 6-25).

conjunction with historical meteorological data for the Milford area (Exh. EPEC-8, p. 4-20). EPEC claimed that the results from the refined analysis predict NO_x and PM concentrations below their corresponding SILs (Exh. EPEC-19, pp. 6-26 to 6-27).[158] Based on this analysis, EPEC concluded that operation of the proposed facility would not affect the NAAQS attainment status of the area surrounding the primary site with respect to SO_2, CO, NO_x or PM (id., p. 6-19).

In their briefs, Tosches and CCAP expressed concern regarding the cumulative impact of the proposed project on ambient air concentrations of O_3, NO_x and CO (Tosches Initial Brief, pp. 2, 14-15, CCAP Brief, p. 9). Tosches argued that EPEC did not adequately address the cumulative impacts on air quality from the proposed project and the Intercontinental Energy Corporation generating facility located in the Town of Bellingham (Tosches Initial Brief, pp. 14-15).

In response, EPEC explained that point-source interactive modeling, which explicitly includes nearby sources of criteria pollutants, was not necessary for the proposed project because the screening and refined dispersion model analyses predicted concentrations below SILs for all criteria pollutants (Tr. 8, pp. 74-76). Specifically, EPEC indicated that Massachusetts' modeling guidelines for NAAQS and MAAQS only require point-source interactive modeling when criteria pollutant concentrations are predicted to be above SILs, and the proposed unit would emit more than 100 TPY of that pollutant (id.).

EPEC claimed that the proposed project would not emit significant quantities of the remaining criteria pollutants: O_3 and lead (Exh. EPEC-8, pp. 4-4, 4-8). As noted above, EPEC explained that the Town of Milford is located in an area which

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158/ EPEC documented predicted peak annual SO_2 concentrations of 0.53 micrograms per cubic meter ("ug/m^3") with the proposed facility at maximum operations and 0.85 ug/m^3 with the proposed facility at 67 percent of maximum operations (id.). EPEC asserted that both measurements are below the significant impact level of one ug/m^3 (id.).

has been classified as non-attainment for O_3 (Exh. EPEC-8, p. 4-4). EPEC further explained that the proposed facility is predicted to emit 53 TPY of VOCs (id.). However, EPEC noted that the proposed facility would not be subject to non-attainment area regulations for O_3 because it would emit less than 100 TPY of VOCs (id.). With regard to lead, EPEC indicated that emissions would be essentially zero because natural gas contains virtually no lead (id., p. 4-12).

EPEC explained that a small percentage of the ammonia injected into the flue gas stream for SCR does not react and is emitted through the stack in what is known as "ammonia slip" (id.). EPEC predicted peak one-hour ammonia concentrations of 53.7 ug/m^3 with the ISCST model, and 5.3 ug/m^3 with the Valley model (Exh. EPEC-19, p. 6-25). EPEC demonstrated that both predicted concentrations are several orders of magnitude below the noticeable odor threshold of 32,700 ug/m^3 (id.).

Finally, EPEC acknowledged that natural gas-fired combined cycle generating facilities, such as that proposed by EPEC, generally emit approximately 1,014 pounds per megawatthour of CO_2 (Exh. HO-E-13). EPEC indicated that it would make a one-time contribution of $5,000 to the Massachusetts Re-Leaf tree-planting program to offset a fraction of the proposed project's CO_2 emissions (Exh. EPEC-19, Appendix B). However, EPEC did not provide any documentation of the amount of CO_2 emissions which would be offset by its $5,000 contribution to Massachusetts Re-Leaf. The Siting Council notes that federal and state air quality regulations currently do not establish emissions limitations for CO_2 and that previous Siting Council reviews of natural gas-fired generating facilities have not addressed CO_2 emissions (See West Lynn, EFSC 90-102, pp. 87-90; MASSPOWER, 20 DOMSC 301 at 384-388; Altresco, 17 DOMSC 351 at 397-400; NEA, 16 DOMSC 335 at 398-401). However, in our recent review of a proposed coal-fired generating facility, the Siting Council required the petitioner to provide a comprehensive analysis of the environmental and economic impacts of attaining a range of CO_2 emission offsets to allow the Siting Council to determine whether CO_2 emissions have been adequately minimized. EEC, EFSC 90-100, pp. 168-169. Although natural gas-fired generating facilities produce significantly less CO_2 than facilities which are fueled by coal, the Siting Council notes that the CO_2 emissions from natural gas-fired facilities are not insubstantial and merit further review. Thus, the Siting Council will require future applicants of proposed generating facilities, regardless of fuel type, to comprehensively address CO_2 emissions, as well as the costs and impacts of possible remedial measures.

EPEC has demonstrated that its proposed facility, if located at the primary site, would produce ambient concentrations of SO_2, CO, NO_x, and PM which will not affect the non-attainment status of the area surrounding the primary site. EPEC also has demonstrated that VOC emissions from its proposed facility, if located at the primary site, would be considerably below the SIL for the Milford area, which is a non-attainment area for O_3. Finally, EPEC has documented that the proposed facility, if located at the primary site, would not emit significant quantities of NO_x, SO_2, lead or ammonia.

Accordingly, the Siting Council finds that the stack emissions of the proposed project at the primary site would have an acceptable impact on air quality.

(B) Alternative Site

EPEC also predicted the emissions of criteria pollutants and resulting ambient concentrations of those pollutants due to operation of the proposed facility at the alternative site (Exhs. EPEC-8, pp. 3-206, 5-1 to 5-46, HO-RR-89).

With respect to NSPS emissions regulations, EPEC indicated that the emissions from the proposed facility would be identical at either the primary site or the alternative site (Exh. EPEC-8, p. 5-1). Thus, EPEC stated that NO_x and SO_2 emissions from the proposed facility at the alternative site would be well below the NSPS limitations and that emissions of lead and ammonia would be below their respective SILs (id.).

EPEC further provided screening level and refined model results which predict that the proposed facility, if constructed at the alternative site, would produce ambient concentrations of criteria pollutants well below the SILs established by NAAQS and MAAQS (id., pp. 5-1 to 5-7). However, EPEC indicated that it changed the vendor for its HRSG during the course of the proceeding, which in turn changed the exhaust stack dimensions and parameters (Exhs. EPEC-19, pp. 3-1 to 3-3, 6-14 to 6-32, HO-RR-89). Although EPEC provided updated models showing the predicted concentrations of criteria pollutants if the proposed facility were constructed at the primary site, EPEC failed to provide a comparable analysis of predicted concentrations at the alternative site with the new HRSG and stack dimensions and parameters (id.).

The Siting Council notes that the predicted ambient concentrations of criteria pollutants at the alternative site, with the initially proposed HRSG, were well below their respective SILs. The Siting Council further notes that these ambient concentrations would have constituted an acceptable impact on air quality. It is highly unlikely that the change in HRSG and subsequent change in stack dimensions and parameters would increase ambient concentrations of criteria pollutants by a magnitude sufficient to raise those concentrations above their respective SILs. Accordingly, the Siting Council finds that the stack emissions of the proposed project at the alternative site would have an acceptable impact on air quality.

iii. Conclusions on Stack Emissions

The Siting Council has found that the stack emissions of the proposed facility at the primary site and the alternative site would have an acceptable impact on air quality. However, because EPEC did not provide dispersion models for the new HRSG and stack at the alternative site, the Siting Council is unable to quantify precisely the expected ambient concentrations resulting from operation of the proposed project at the alternative site. Accordingly, the Siting Council makes no finding whether the impact on air quality of the stack emissions are preferable at the primary site or the alternative site.

b. Cooling Tower Emissions

EPEC analyzed two potential impacts from cooling tower emissions: (1) adverse health impacts associated with the theoretical release of pathogenic microorganisms or the inhalation of potential volatile organic chemical emissions, and (2) fogging and icing on local roadways (Exh. EPEC-8, pp. 4-30, 4-160 to 4-175).

With regard to potential adverse health effects from cooling tower emissions, EPEC first analyzed the potential release of pathogens, such as bacteria, present in the effluent which would be used as cooling water (id., pp. 4-160 to 4-166). EPEC cited epidemiological studies of pathogens in wastewater which it claimed do not show a link between wastewater treatment facilities and adverse health effects on surrounding populations (id.). EPEC further maintained that pathogens are extremely unlikely to survive the MWTP's tertiary treatment process, and even less likely to survive once released from the warm, moist environment of the cooling tower (id.). Thus, EPEC concluded that the potential release of pathogens from the proposed cooling tower, whether located at the primary or the alternative site, presents a negligible public health risk (id.; Tr. 9, pp. 21-22).

EPEC next analyzed the potential adverse health effects from inhalation of volatile organic chemicals released by the cooling tower (Exh. EPEC-8, pp. 4-166 to 4-175). EPEC stated that it performed an extremely conservative screening analysis which first identified potential chemicals of concern, then identified toxicity levels established by the US EPA for those chemicals, and finally estimated the likely dose of those chemicals at the point where they would be inhaled (id.). Even with extremely conservative modeling assumptions, EPEC maintained that its analysis shows no public health risk as a result of the potential release of volatile organic chemicals from the proposed cooling tower, whether located at the primary or the alternative site (id.; Tr. 9, pp. 9-11).

Finally, EPEC analyzed potential fogging and icing as a result of operation of the proposed cooling tower (Exh. EPEC-8, p. 4-30). EPEC explained that fogging can occur when the water vapor in the cooling tower plume combines with ambient water vapor to saturate the air in the plume (id.). EPEC further explained that icing can result from contact of the visible plume with road surfaces or deposition of small water droplets on surfaces when temperatures are below freezing (id.). To measure the likelihood of plume-induced fogging or icing at the primary or alternative site, EPEC used the Seasonal and Annual Cooling Tower Impacts ("SACTI") model developed by Argonne National Laboratory for the Electric Power Research Institute (id.). EPEC maintained that the results of the SACTI model show that the proposed cooling tower would not cause fogging or icing of local roadways at either the primary or the alternative site (id.).

EPEC has provided extensive documentation to support its position that the possibility of adverse health effects resulting from operation of the proposed cooling tower at the primary site or the alternative site is extremely remote. EPEC further has demonstrated that operation of the proposed cooling tower at the primary site or the alternative site should not result in fogging or icing.

Accordingly, based on the foregoing, the Siting Council finds that operation of the proposed facility cooling tower would have acceptable air quality impacts at the primary site or the alternative site. The Siting Council further finds that the primary site and the alternative site are comparable with respect to air quality impacts associated with the proposed cooling tower.

6. Impact on Other Water Users

In this section, the Siting Council examines the impact of the proposed facility on other water users in the upper

Charles River basin. Specifically, the Siting Council reviews the impact of construction and operation of the proposed facility on the Godfrey Brook wellfield, which provides water to the MWC, and on future water withdrawals from the upper Charles River.

a. Primary Site

EPEC stated that the Godfrey Brook wellfield, from which the MWC is permitted to withdraw 0.58 MGD of water, is located approximately 600 feet north of the primary site boundary (Exhs. HO-RR-57, EPEC-8, p. 3-17). EPEC indicated that the primary recharge area supplying the Godfrey Brook wellfield extends from north to south along the Charles River from a location approximately one-half mile north of the wellfield, then under the wellfield and the primary site for the proposed facility to a location just north of the MWTP (Exh. HO-E-26).

EPEC addressed two potential impacts of construction and operation of the proposed facility at the primary site on the Godfrey Brook wellfield: contamination and loss of supply (Exhs. EPEC-8, pp. 4-68 to 4-70, EPEC-19, pp. 6-73 to 6-77, HO-RR-61). EPEC demonstrated that contamination potentially could result from chemical spills or the presence of contaminants such as oil and grease in stormwater runoff from the site (Exhs. EPEC-8, pp. 4-68 to 4-70, EPEC-19, pp. 6-73 to 6-77).

In order to protect the primary recharge area for the Godfrey Brook wellfield from possible chemical spills, EPEC stated that the proposed facility would include a spill containment system to prevent any release of stored chemicals to groundwater (Exh. EPEC-19, pp. 6-72 to 6-75). EPEC indicated that operation of the proposed facility would require storage of lubricating oils and industrial chemicals in an enclosed containment area on site (id., p. 2-20). EPEC explained that the containment area would consist of chemical storage tanks located on a paved surface with impervious dikes and/or curbs, which would direct spilled materials to a chemical sump and to a neutralization tank for further treatment as necessary (id.). Further, EPEC stated that, pursuant to a Special Permit issued by the Town of Milford Zoning Board of Appeals, EPEC will submit a Spill Prevention, Containment and Control Plan ("SPCCP") to the Milford Fire Chief for approval by the MWC prior to construction of the proposed facility (id., Appendix B).[159] EPEC claimed that the SPCCP would include: (1) a list of all chemicals to be used and stored at the site during construction and operation of the proposed facility; (2) a description of design measures to prevent spills; and (3) procedures for responding to spills and other plant emergencies (id.).

In order to protect the primary recharge area for the Godfrey Brook wellfield from contaminated stormwater runoff, EPEC claimed that stormwater runoff would be collected from parking lots and other impervious surfaces, then passed through oil-water separators and directed to a detention pond (id., p. 6-74). EPEC further indicated that the detention pond would be large enough to accommodate precipitation from a "design" storm with an expected recurrence frequency of once in ten years, and that in such instances water accumulated in the detention pond would be used as cooling tower make-up water (id.). EPEC stated that runoff from extreme precipitation events would be transported to a lined detention basin, where metals and particulates would settle out (id.; Tr. 6, p. 135). EPEC indicated that the runoff would be released gradually into the Charles River (id.). EPEC's witness, Mr. Stroble, testified

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159/ EPEC indicated that the Town of Milford voted at a June 27, 1990 Town Meeting to amend the Town's by-laws to require issuance of a Special Permit by the Zoning Board of Appeals prior to construction of any generating facility in the Town of Milford (Exh. EPEC-16, p. 3). EPEC presented the Special Permit issued by the Town of Milford Zoning Board of Appeals for construction and operation of the proposed facility at the primary site (id.). The Special Permit includes 56 conditions and requirements governing construction and operation of the proposed facility (id.). Attachment A is a copy of the Special Permit.

that stormwater would be discharged to the Charles River pursuant to an NPDES permit, and that an upgrade is likely to be required to bring an existing stormwater discharge point from the railroad right-of-way just east of the site to a location nearer to the river (Tr. 6, pp. 129-139). In addition, EPEC indicated that the Special Permit requires EPEC to submit a Stormwater Control and Discharge Plan to the Town Engineer, which would provide for on-site groundwater monitoring to detect stormwater detention basin leaks and chemical spills (Exh. EPEC-19, Appendix B).

The Special Permit includes the further requirement that EPEC, in cooperation with the MWC, submit a plan to the Town Health Inspector (id.). Specifically, the Special Permit requires a plan for evaluating groundwater flow and soil and water quality in and around the Godfrey Brook wellfield both prior to construction and during operation of the proposed facility (id., Appendix B).

With regard to potential loss of supply to the Godfrey Brook wellfield resulting from construction and operation of the proposed facility, EPEC argued that no impact is expected on either the surface or groundwater capacity of the sources which supply water to the MWC (EPEC Initial Brief, p. V-43). Specifically, EPEC asserted that no impact on future water supplies is expected to result from the proposed effluent diversion because the effluent discharge point at the MWTP is nearly one mile downstream from the Godfrey Brook wellfield, and a significant elevation differential exists between the wellfield and the MWTP (Exh. EPEC-8, p. 4-68). Further, EPEC claimed that the proposed facility design ensures that current infiltration rates would not be changed (Exh. HO-RR-61).

The final impact on other water users addressed by EPEC is the potential reduction in the amount of water available to be permitted for withdrawal from the upper Charles River due to the proposed effluent diversion (Exh. EPEC-8, p. 4-65). EPEC explained that the amount of water available for withdrawal is based upon the minimum streamflow guideline established by the

WRC (id.). Specifically, EPEC asserted that water is permitted for withdrawal up to the amount which would cause flows below the minimum streamflow guideline (three cfs for the upper Charles River) to occur more than ten percent of the time (id.). EPEC indicated that, currently, 1.93 cfs of water is available for withdrawal from the upper Charles River basin above Box Pond (id., pp. 4-65 to 4-66). EPEC acknowledged that the 1.93 cfs currently available for withdrawal would be reduced by the amount of the proposed effluent diversion (1.35 cfs) as a result of operation of the proposed facility (Tr. 4, pp. 166-167). EPEC noted that use of effluent for cooling purposes conserves potable water resources, and, as such, is consistent with the Water Management Act and other state policies (Exh. EPEC-19, p. 5-2, EPEC Initial Brief, pp. V-90 to V-91). EPEC further stated that there is no policy which prohibits allocation of most or all of the water available for withdrawal to a single user (Tr. 4, pp. 166-167).

CCAP argued that construction of the proposed facilities at the primary site would disturb the integrity of the aquifer supplying the Godfrey Brook wellfield, and would provide a path for contamination of the wellfield (CCAP Initial Brief, p. 7). CCAP further argued that operation of the proposed facilities presents the potential for further risk because of the high water table in the vicinity of the proposed project (id.). EPEC merely responded that the record evidence is to the contrary of CCAP's expressed concern regarding potential contamination of the aquifer (EPEC Reply Brief, p. 26).

The record demonstrates that construction of the proposed facility at the primary site would pose some risk of contamination to the Godfrey Brook wellfield due to the location of the site above the primary recharge area for the wellfield. However, EPEC has documented numerous protective features incorporated into the design of the proposed facility which will minimize the risk of potential contamination of the wellfield from chemical spills and stormwater runoff. In addition, to protect the wellfield, EPEC must comply with the Special Permit requirement to develop and receive appropriate approval for the SPCCP, the Stormwater Control and Discharge Plan, and the groundwater analysis. The comprehensive protective measures already incorporated into EPEC's proposed facility design, in conjunction with the SPCCP, Stormwater Control and Discharge Plan and groundwater analysis, provide assurance that construction and operation of the proposed facility at the primary site would not result in contamination of the primary recharge area for the Godfrey Brook wellfield. The Siting Council ORDERS EPEC to submit to the Siting Council the approved SPCCP, Stormwater Control and Discharge Plan, and the groundwater analysis plan, as specified in the Special Permit. Accordingly, based on EPEC's compliance with the above ORDER, the Siting Council finds that EPEC has adequately minimized the risk of potential contamination of the Godfrey Brook wellfield due to construction and operation of the proposed project at the primary site.

The record further demonstrates that the Godfrey Brook wellfield will not experience a loss of supply due to operation of the proposed facility because the point at which the diverted effluent currently enters the Charles River is downstream from, and at a lower elevation than, the primary recharge area for the wellfield. In addition, should any change in groundwater flow patterns result from operation of the proposed facility at the primary site, such changes will be detected by the groundwater analysis to be performed prior to construction and during operation of the proposed facility. The Siting Council ORDERS EPEC to immediately notify the Siting Council and MDEP of any changes in groundwater flow patterns in the primary recharge area of the Godfrey Brook wellfield due to operation of the proposed facility and to submit plans to MDEP to remedy any adverse impact on groundwater resulting from operation of the proposed facility.

Finally, the record demonstrates that operation of the proposed facility could substantially reduce the amount of water available to be permitted for withdrawal from the upper Charles facility would rely upon the same quantity of effluent from the MWTP whether constructed at the primary or the alternative site, the impacts on future water withdrawals from the upper Charles River would be identical at both sites (id.).

Accordingly, based on the foregoing, the Siting Council finds that construction and operation of the proposed facility at the alternative site would have an acceptable impact on other water users.

c. Conclusion

The Siting Council has found that the proposed facility, whether constructed at the primary site or the alternative site, would have an acceptable impact on other water users. In finding that the proposed facility would have an acceptable impact on other water users if constructed at the primary site, the Siting Council first found that EPEC has adequately minimized the risk of contamination of the primary recharge area supplying the Godfrey Brook wellfield. Nevertheless, because no protective system can be completely fail-safe, some small risk exists that the contaminants from the proposed project could reach the wellfield. At the same time, the alternative site is not located in close proximity to any public water supply.

Accordingly, the Siting Council finds that the alternative site is slightly preferable to the primary site with respect to impacts on other water users.

7. Noise

EPEC asserted that operation of the proposed facility at the primary site would result in noise increases at residential receptors that are within MDEP guidelines of ten decibels (EPEC Initial Brief, p. V-59). EPEC further argued that operation of the proposed facility at the primary site would not result in noise impacts of a noticeable level at residential receptors, given that the expected noise increases at such receptors would not exceed five decibels (id.). EPEC asserted that operation of the proposed facility at the alternative site would result in noise increases much greater than ten decibels, in the absence of extensive noise mitigation, and concluded that the primary site is more appropriate for facility development than the alternative site in terms of noise impacts (id., pp. V-80 to V-81).

EPEC stated that MDEP has established noise criteria for the approval of new facilities which limit allowable increases in noise to ten decibels (Exh. EPEC-8, p. 4-138). EPEC stated that the Town of Milford also regulates noise in conjunction with Town zoning by-laws, and specifically requires that noise originating within an industrial district shall not "normally be perceptible" more than 100 feet within a residential district (id.). EPEC indicated that the Town of Milford has issued a Special Permit for the proposed facility at the primary site which establishes a more specific basis for ensuring the facility's compliance with the Town's noise requirements (Exh. EPEC-19, Appendix B). (See Section III.6, above, for a description of the Special Permit). The record indicates that the Special Permit limits increases in noise levels at specified property line and residential receptors around the primary site to four decibels, as determined by comparing future measured noise levels during operation of the facility to existing baseline noise levels (id.).[161]

As the basis for its analysis of noise impacts, EPEC provided comparisons of existing noise levels with expected modeled noise levels during construction and operation of the proposed facility, reflecting both daytime and nighttime conditions at the primary and alternative sites (Exh. EPEC-8, pp. 4-138 to 4-145, 5-30 to 5-34).[162] EPEC indicated that its

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161/ The Special Permit provides that modeled noise increases of up to five decibels would be consistent with the noise compliance requirement for the proposed facility, given that modeled estimates of facility noise impacts tend to be conservative (i.e., tend to overstate facility noise impacts) (Exh. EPEC-19, Appendix B).

162/ EPEC stated that existing noise levels were measured under winter conditions, when background noise generally is lowest (Exh. EPEC-8, p. 3-175).

noise estimates were developed for a property line location and three nearby residential receptor locations at both the primary and alternative sites (id.). In order to estimate operational noise impacts, EPEC stated that it assumed common facility elements and noise control features for the primary and alternative sites, including a wet cooling tower fitted with sound abatement equipment and a building to enclose the gas turbine and the steam turbine (id., p. 4-142, 5-32). In order to estimate construction noise impacts, EPEC stated that it assumed construction noise sources at the primary and alternative sites would contribute 126.5 decibels of noise during maximum construction activity and 113 decibels of noise during average construction activity, as measured at a distance of 50 feet from the construction activity (id., pp. 4-139, 5-30).

For the primary site, EPEC's analysis shows that the maximum noise increases resulting from operation of the proposed facility at the property boundary is 2.5 decibels in the daytime and 3.0 decibels at night (id., p. 4-144). EPEC's analysis further shows that the maximum residential receptor noise increases resulting from operation of the proposed facility would be 3.0 decibels in the daytime, occurring at two receptors to the northeast and northwest, and 4.8 decibels at night, occurring at the northwest receptor (id., p. 4-144). The maximum resultant residential noise levels would be 52.0 decibels in the daytime and 50.8 decibels at night, occuring at the northwest receptor (id.). With respect to construction noise, EPEC's analysis shows a maximum residential receptor increases of 5.5 decibels during maximum construction activity and 1.8 decibels during average construction activity, occurring at the northwest receptor (id., p. 4-141).

For the alternative site, EPEC's analysis shows that expected residential receptor noise increases resulting from operation of the proposed facility would exceed ten decibels at two receptors, with a maximum daytime increase of 22.1 decibels and a maximum nightime increase of 20.1 decibels at the southeast receptor (id., p. 5-33). The maximum resultant residential noise levels would be 57.1 decibels both during the day and at night, occurring at the southeast receptor (id.). With respect to construction noise, EPEC's analysis shows maximum residential receptor increases of 17.1 decibels during maximum construction activity and 4.1 decibels during average construction activity, occurring at the southeast receptor (id., p. 4-141).

While providing estimated noise impacts for the alternative site that exceed MDEP guidelines, EPEC stated that it could incorporate additional noise mitigation, consistent with the project budget, which would allow MDEP criteria to be met at the property line as well as at the residential receptors (Tr. 9, pp. 107-109). Such a limitation would require that the expected daytime noise level at the nearest residential receptor (the southeast receptor) during operation of the proposed facility be held to 45.0 decibels, rather than the 57.1 decibel level presented in EPEC's analysis (id.).[163]

Tosches argued that EPEC's goal of limiting routine noise levels from the proposed facility at the primary site to no greater than 51 decibels is unattainable (Tosches Initial Brief, p. II-7). Tosches asserted that the nearby existing Foster Forbes facility produces extreme noise levels, and has been a nuisance to residents in the area for years (id., p. II-6). Noting that the primary site is within 0.2 kilometers of the Foster Forbes facility, Tosches argued that the added noise from the proposed facility would create a nuisance and undue burden

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163/ With respect to the property line receptor, compliance with the MDEP ten decibel guideline would require that the expected property line nightime noise level during operation of the proposed facility be held to 47.0 decibels, as compared to a level of 64.0 decibels estimated in EPEC's analysis (Exh. EPEC-8, p. 5-33). The Siting Council notes that meeting the 47.0 decibel limit at the property line could result in maintaining a somewhat lower noise level at the nearest residence. In addition, EPEC stated that in developing additional noise mitigation for the alternative site, it also could meet the Town of Milford requirement that noise not be normally perceptible at residences (Tr. 9, pp. 108-109).

on employees at the proposed facility, and or residents in the Pheasant Run apartments (id., p. II-7). CCAP argued that existing noise levels in residential areas near the primary site, especially at Pheasant Run apartments, are sufficiently high such that the additional noise expected during construction of the proposed facility would be unacceptable (CCAP Brief, p. 6).

In past decisions, the Siting Council has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental requirements, including the MDEP's ten decibel guideline. EEC, EFSC 90-100 at 183; West Lynn, EFSC 90-102 at 97; MASSPOWER, 20 DOMSC at 85; Altresco-Pittsfield, 17 DOMSC at 401. In addition, the Siting Council has considered the significance of expected noise increases which, although lower than ten decibels, may adversely affect existing residences or other sensitive receptors such as schools. EEC, EFSC 90-100 at 177-186; Altresco-Pittsfield, 17 DOMSC at 401; NEA, 16 DOMSC at 402-403.

Here, operation of the proposed facility at the primary site would result in residential receptor noise increases that not only are within the MDEP ten decibel guideline, but are less than half that amount. In addition, EPEC is specifically required by its local zoning permit to hold increases in measured noise levels at both property line and residential receptors to four decibels during operation of the proposed facility -- a level which ensures that residents would, at most, barely perceive any difference from current conditions.

The Siting Council agrees with intervenors that existing high levels of background noise at the primary site are a potential factor in assessing whether expected noise increases from a new generating facility are acceptable. The Siting Council notes that the expected ambient residential receptor noise levels at the primary site during operation of the proposed facility, combining background noise and facility noise, are among the largest presented in recent Siting Council reviews of proposed generating facilities. See e.g., EEC, EFSC 90-100 at 181; MASSPOWER, 20 DOMSC at 390; NEA, 16 DOMSC at 401-402. In addition, despite the proximity of residential receptors to the primary site, EPEC failed to provide comparisons of expected noise levels to ambient noise guidelines or studies that relate environmental noise conditions to levels of public health and well-being -- comparisons which have been provided in previous Siting Council reviews where residential noise impacts were at issue. See e.g., EEC, EFSC 90-100 at 181; MASSPOWER, 20 DOMSC at 390; NEA, 16 DOMSC at 402.

Despite the relatively high level of background noise at the primary site, however, EPEC has reasonably established that any noise increases resulting from operation of the proposed facility have been substantially minimized and would at most be barely perceptible at residential receptors. There is no evidence in the record that indicates that area residents would be adversely affected by facility noise impacts which conform to the Town of Milford requirement that such increases not be normally perceptible. Although expected noise increases during maximum construction activity would be slightly higher than during operation of the proposed facility, the noise impacts associated with such activity would be of limited duration and confined to daytime hours.

Accordingly, the Siting Council finds that the proposed facility would have an acceptable impact on community noise levels at the primary site.

With respect to the alternative site, EPEC has indicated that operation of the proposed facility would result in noise increases at residential receptors more than twice the ten-decibel increase allowed by MDEP. However, EPEC has stated that it could meet the ten-decibel guideline at the property boundary through additional mitigation measures. Further, to the extent that the MDEP guideline is met at the property line, it is likely that residential receptor noise increases could be held to less than ten decibels.

Accordingly, the Siting Council finds that operation of the proposed facility at the alternative site, with the mitigation measures described above, would have a minimally acceptable impact on community noise levels.

In comparing the primary and alternative sites, EPEC's analysis shows that, without additional mitigation at the alternative site, the estimated residential receptor noise levels and the associated increases over background levels would be higher at the alternative site than at the primary site. The Siting Council notes that if such additional mitigation measures were provided at the alternative site, resulting ambient noise levels would be less than ambient noise levels at the primary site. However, the increase in noise levels at the alternative site property boundary still would be twice as large as the increase in noise levels at the primary site property boundary. Further, it is extremely unlikely that the ten decibel increase at the property boundary would drop to a level comparable to, or lower than, the maximum 4.8 decibel increase at a residential receptor for the primary site.[164]

Accordingly, the Siting Council finds that the primary site is preferable to the alternative site with respect to impacts to community noise levels.

7. Land Use

EPEC asserted that the proposed project, whether it is situated on the primary site or the alternative site, is consistent with the development objectives identified in the Town of Milford's land use plan (Exh. EPEC-8, p. 3-157). EPEC

164/ Although EPEC has stated that additional mitigation at the alternative site would bring the noise increase at the property boundary to ten decibels, EPEC failed to document the resulting level of increase at residential receptors. In this instance, an analysis of the impact on noise levels at the residential receptors due to operation of the proposed facility at the alternative site would have allowed for a more accurate comparison of the noise impacts at the primary and alternative sites. The Siting Council emphasizes that all developers of proposed facilities are obligated to provide detailed information regarding the impacts of the proposed facility at both the primary site and the alternative site(s).

stated that both the primary site and the alternative site are located in industrially zoned districts which allow gas-fueled power generation plants (id., Exh. EPEC-16, Tab F). EPEC argued that the primary site is more appropriate than the alternative site with respect to land use, because the primary site already has been filled and graded to accommodate development while the alternative site would require considerable alteration of existing topography and disturbance of natural resource areas in order to install the proposed facility and related utility interconnections (EPEC Initial Brief, pp. V-75, V-76 to V-77).

a. Primary Site

EPEC stated that the primary site consists of 6.8 acres of land which is located in an industrial area and has been previously disturbed (Exh. EPEC-19, p. 2-1). EPEC stated that the primary site is presently used as a truck parking area for the Foster Forbes glass manufacturing complex, which is located across National Street to the south of the site (Exh. EPEC-8, p. 3-153). EPEC identified additional abutting land uses as the Vernon Grove Cemetery (owned by the Town of Milford) to the west; the Conrail railroad tracks to the east; and vacant land and Godfrey Brook to the north (id.). In addition, EPEC stated that the Charles River is located 400 feet to the east of the primary site at its closest point (id.).

EPEC indicated that the nearest residence to the primary site is located 1,000 feet to the southeast on Howard Street, and that a 138-unit apartment complex is located 1,200 feet to the northwest (Exh. EPEC-8, p. 3-153; Tr. 9, p. 107). EPEC asserted that the apartment complex is separated from the site by Vernon Grove Cemetery, Godfrey Brook, a railroad spur, and a stand of conifer trees (Exh. EPEC-8, p. 3-153).

Beyond the nearest abutters, EPEC stated that there are commercial uses to the west and south, including a shopping center 1,500 feet from the site (id.). EPEC indicated that heavily built up residential areas are located to the north and west, beyond the cemetery and the apartment complex (id.)

EPEC identified the surrounding zoning districts as industrial to the northeast, east, south, and southwest; and residential to the west and northwest (id., Figure 3.1.6-2).

EPEC stated that it has received two variances in addition to the required Special Permit from the Town of Milford Zoning Board of Appeals: (1) to construct a fence taller than the permitted height for visual screening, and (2) to exceed the maximum building height (Exh. EPEC-19, Appendix B).[165] EPEC stated that the Zoning Board of Appeals determined that the fence is necessary for acoustical and visual protection, and that granting the fence-height variance would serve the public interest and the public good (id.). EPEC stated that the the height of the roof of the generator would be 56 feet, which would be below the 60-foot zoning height limitation, but that the height of the ancillary platform and piping would be 86 feet (id.; Tr. 8, p. 57). EPEC also stated that the structures on the Foster Forbes site range from 85-125 feet and that the Zoning Board of Appeals determined that granting the building height variance would not be detrimental to the public good (Exh. EPEC-19, Appendix B).

EPEC argued that the utility corridor requirements for the primary site make maximum use of existing rights-of-way and the planned Town sewer easement (EPEC Initial Brief, p. V-77). EPEC indicated that utility interconnections to the primary site would be necessary as follows: (1) a 3,500 foot effluent supply pipeline, of which 2,500 feet would be parallel to and constructed at the same time as a planned Town of Milford sewer

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165/ In addition to a building height variance, EPEC stated that it initially sought a lot width variance in conjunction with its plan to subdivide the existing 6.8 parcel into two new parcels of 4.3 acres and 2.5 acres (Exh. EPEC-19, Appendix B). EPEC indicated that the Zoning Board of Appeals denied EPEC's request for a variance due to insufficient lot width in the 2.5 acre subsection (id.). The Siting Council notes that EPEC's purchase and sale agreement was amended on April 8, 1991 to include the full 6.8 acre parcel as the primary site, thereby negating the need to subdivide the existing parcel (Exh. HO-RR-82).

line; (2) a 1,000 foot sewer line to the planned Town of Milford sewer line; (3) two 1,500 foot electric transmission lines to existing NEPCo transmission lines; and (4) a 100 foot tie-in to Algonquin's natural gas facilities adjacent to the site (Exh. EPEC-19, pp. 2-2, 2-10, 2-19) (see Section III.C.5.a, above).

CCAP submitted that Milford's zoning by-laws were promulgated for the benefit of the citizens of Milford, and should not be altered for the benefit of private enterprise (CCAP Brief, p. 6). In addition, CCAP stated that granting the variance and building the facility would cause harm to the neighborhood (id.).

The Siting Council notes that this is its first review of an IPP facility. In recent reviews of cogeneration facilities, the Siting Council has reviewed proposed sites that either were a part of larger industrial complexes serving as a steam host for such facilities, or were significantly larger than the primary site in this review. EEC, EFSC 90-100 at 208-211; West Lynn, EFSC 90-102 at 97-98; MASSPOWER, 20 DOMSC at 70-72; Altresco-Pittsfield, 17 DOMSC at 34-37; NEA, 16 DOMSC at 54-56. While the primary site is abutted by an existing industrial land use to the south and a cemetery to the west, the small size of the primary site creates difficulties in providing natural buffers from the surrounding community, which in this case includes extensive residential areas.

Nonetheless, the Siting Council notes that, through the Town of Milford's Special Permit process and other forms of public participation, EPEC's development of its facility proposal reflects numerous design features and safeguards to minimize any incompatibility with surrounding land use. For example, the proposed stack height is significantly lower than what has been presented in recent Siting Council reviews of generating facilities (EEC, EFSC 90-100 at 124-125; West Lynn, EFSC 90-102 at 97-98; MASSPOWER, 20 DOMSC at 70-72; Altresco-Pittsfield, 17 DOMSC at 34-37; NEA, 16 DOMSC at 46-48), and the Town's Special Permit for the proposed facility requires that community noise levels be, at most, barely perceptible (see Section III.E.7, above). The Siting Council further notes that use of the primary site would minimize alteration of presently undisturbed land.

Accordingly, based on the foregoing, the Siting Council finds that use of the primary site would have an acceptable impact with respect to land use.

b. Alternative Site

EPEC stated that the alternative site consists of 48 acres, owned by the Town of Milford (Exh. EPEC-19, p. 2-1). EPEC stated that the alternative site is presently an undeveloped, heavily wooded parcel of land, characterized by numerous changes in topographic relief (EPEC Initial Brief, p. V-10). In addition, EPEC stated that the southern portion of the site contains a ten-acre wetland, and that the proposed facility therefore would be located in the upper northeast quadrant of the site (Exhs. EPEC-8, p. 3-218, HO-S-9).

EPEC indicated that the abutting land is undeveloped, also consisting of hilly, wooded terrain (Exh. EPEC-8, p. 3-218). EPEC stated that beyond the rim of undeveloped land is the Birchwood Business Park to the northeast, commercial and industrial uses and single family dwellings to the north and east, and areas of undeveloped land to the west and south (id.). EPEC indicated that the nearest residence is 600 feet to the east on Beaver Street, and that residences exist along Central Street, 1,700 feet from the building site (id.).

EPEC stated that Town officials had encouraged representatives of the petitioner to consider the alternative site for the proposed facility (Exh. EPEC-1, p. III-52). However, EPEC stated that the Town of Milford has prepared a marketing plan for selling town-owned industrial land, and that the Town now would prefer to hold the alternative site property for potential sale in the future in a more favorable real estate market (Tr. 9, pp. 126-127). In addition, EPEC noted that the proposed facility would only comprise seven acres of the 48 acre alternative site, and that therefore the site may be better used for alternative commercial uses (Exhs. EPEC-1, p. III-22, EPEC-19, p. 7-3).

EPEC argued that use of the alternative site would require additional utility interconnection easements in undisturbed, forested lands, as well as in several wetland areas (EPEC Initial Brief, p. V-77). EPEC indicated that utility interconnections to the alternative site would require: (1) two 2,300 foot transmission lines to the existing NEPCo transmission lines; (2) an approximately 2.5 mile effluent supply pipeline that would extend approximately one mile along new right-of-way and existing NEPCo right-of-way to the Town sewer easement in the vicinity of the primary site, and then parallel the Town sewer as under the primary site; (3) an approximately 1.5-mile sewer line that would follow the same route as the effluent supply line to the Town sewer; and (4) an approximately 1.5-mile natural gas pipeline that would follow the same route as the effluent supply and sewer lines to the vicinity of the primary site, where it would be tied in with the Algonquin pipeline system (Exh. EPEC-19, pp. 2-2, 2-10, 2-19). EPEC indicated that the routes of the various utility lines to the alternative site would partially follow new right-of-way, as well as widened right-of-way parallel to the NEPCo transmission lines, extending in both cases through undisturbed, forested land (id.).

The Siting Council notes that use of the alternative site is consistent with the development goals as stated in the Town's land use plan. In addition, while EPEC points out that the proposed facility would only require seven acres for active development, the Siting Council notes that use of the full 48-acre alternative site would provide important opportunities to buffer the proposed facility from surrounding land use, as well as avoid disruption of wetlands and any other sensitive resources within the site itself.

With respect to utility interconnections, the alternative site would require an additional right-of-way corridor extending approximately one mile through an undeveloped, wooded area, as well as construction of the 3,500-foot effluent supply line segment parallel to the planned Town sewer line along the Charles River which would be part of the project at either the primary or alternative site. The Siting Council notes that the land use impact of the additional right-of-way corridor extending to the alternative site, including related tree clearing, wildlife habitat disturbances and possible landowner conflicts, would be minimized by paralleling the NEPCo right-of-way.

Accordingly, based on the foregoing, the Siting Council finds that use of the alternative site would have an acceptable impact with respect to land use.

c. Conclusion

The Siting Council has found that the proposed facilities would have an acceptable impact on land use at both the primary and alternative sites.

The record indicates that the primary site offers the advantage of a previously disturbed site located in an industrial area, while the alternative site offers the advantage of a natural buffer from surrounding community development. However, despite the industrial character of the primary site and the presence of the adjacent Foster Forbes complex, the primary site is not part of a larger industrial complex, nor within an industrial park or district with a number of industries. Given its small size, and the presence of nearby residential and commercial areas, the primary site unavoidably involves some measure of incompatibility with existing land use.

Nonetheless, the record indicates that Town of Milford officials favor use of the primary site because of the relative economic advantages to the Town. In addition, as a result of design features and safeguards included in the proposed facility, which has been incorporated largely in response to the Town's Special Permit review and other public participation, potential community concerns such as visual impacts and noise have been substantially minimized. The record demonstrates that such efforts can, and in this case largely do, offset the inherent advantages of the larger alternative site in offering natural buffer from the surrounding community.

In addition, from the perspective of utility interconnections, the primary site offers clear advantages over the alternative site with respect to land use. The primary site requires significantly shorter utility easements, and thereby best minimizes impacts on land resources related to acquiring, clearing and constructing in such easements.

Accordingly, based on the foregoing, the Siting Council finds that the primary site is preferable to the alternative site with respect to land use.

9. Safety

EPEC stated that its proposed generating facility would require storage of industrial chemicals including aqueous ammonia (Exh. EPEC-8, p. 2-21).[166] EPEC indicated that chemical storage requirements would be identical at both the primary and the alternative sites (Exh. EPEC-1, pp. IV-67 to IV-72). Tosches noted a general safety concern regarding the storage and transport of industrial chemicals in the community (Exh. T-1, pp. 4, 6). EPEC asserted that its chemical storage systems would operate safely due to (1) installation of containment systems, and (2) development of an emergency response plan (Exh. CCAP-E-22(2)).

EPEC indicated that above-ground storage tanks would be utilized for storage of chemical substances (Exh. EPEC-1, pp. IV-67 to V-72). EPEC stated that all chemical storage tanks would be located on paved surfaces and that two types of

166/ EPEC reported that aqueous ammonia would be required for its SCR emissions control system and that other chemicals such as caustic soda, phosphates, and chlorine would be used to demineralize and treat water (Exhs. EPEC-19, pp. 2-20, 2-21; EPEC-1, pp. IV-67, IV-71). Industrial gases such as hydrogen and nitrogen, and maintenance supplies including oils, greases, and paints, also would be used at the facility (Exh. EPEC-1, pp. IV-67 to IV-72).

containment systems would be installed (Exh. EPEC-8, p. 2-21). The first type of containment system -- impervious dikes capable of containing 110 percent of tank capacity -- would be installed at EPEC's aqueous ammonia and neutralization tanks (Exh. EPEC-1, p. IV-72). The second containment system -- utilizing 8-inch curbs and a system of drains -- would be installed at the remaining tanks (Exh. EPEC-19, p. 2-20). In the event of leaks or spills, chemicals would flow through underground drains to a collection sump for treatment or transfer (Exh. EPEC-19, p. 2-20). EPEC claimed that its chemical storage facilities would be designed to meet the most current governmental and industry standards (Exh. EPEC-8, p. 2-23). Further, EPEC argued that its employees would be fully trained in proper handling and storage techniques relating to industrial chemicals (id., p. 2-25; Exh. EPEC-1, p. IV-72). EPEC also noted that EPC has compiled a safety record of 1,597 days without an injury at its Texas City facility and 881 days without an injury at its Clear Lake facility (Exh. CCAP-PV-5(2)).

In addition, EPEC stated that a Spill Prevention Control and Countermeasure ("SPCC") Plan would be prepared in accordance with requirements of the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") (Exh. EPEC-1, p. IV-72). EPEC indicated that its SPCC plan would delineate prevention practices, emergency contacts, and disposal practices, and that the plan would be submitted to the Milford Fire Chief (Exhs. EPEC-1, p. IV-72; EPEC-19, Appendix B; Exh. CCAP-E-22(2)).[167]

The Siting Council notes that EPEC has described the major physical characteristics of its chemical storage facilities. In addition, the Siting Council notes that EPEC intends to develop an emergency plan similar to plans found acceptable in previous Siting Council decisions. MASSPOWER, 20 DOMSC at 399-401; Altresco-Pittsfield, 18 DOMSC at 406-408.

167/ The Siting Council has ordered EPEC to provide its approved SPCC to the Siting Council in Section III.E.6, above.

Nonetheless, in previous reviews of generating facilities utilizing ammonia, the Siting Council was provided with dispersion modeling data which estimated off-site concentrations likely to result from a catastrophic failure of ammonia storage facilities.[168] Id. Here, information regarding the likely concentrations of ammonia at the site boundary in the event of a total tank failure has not been provided by EPEC.[169] Accordingly, the Siting Council ORDERS EPEC to demonstrate that it has included mitigation measures, such as enclosed containers, in its facility design which ensure that ammonia concentrations would not exceed 500 ppm at the site boundary under worst case conditions of ammonia release, or, in the alternative, to perform a dispersion modeling analysis which demonstrates that an off-site limit of 500 ppm will not be exceeded under worst case conditions with the mitigation measures currently incorporated in the proposed facility design.

EPEC claimed that its chemical transport -- using tanker truck delivery -- would comply with all applicable standards including those of the U. S. Department of Transportation (Exhs. EPEC-8, p. 2-23; EPEC-1, p. IV-69). In addition, EPEC noted that truck deliveries would occur infrequently (Exh. EPEC-19, p. 2-21). EPEC estimated that one chemical -- aqueous ammonia -- would require weekly deliveries, while the remaining chemicals would be delivered at a rate of once per month or less (id.). Further, the Special Permit designated a specific truck route through the Town of Milford, with provisions for rerouting based on recommendations of the Town

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168 In each instance, the project proponent demonstrated that the expected concentration of ammonia at the site boundary would not exceed a level of 500 ppm under worst case conditions. See MASSPOWER, 20 DOMSC at 399-400; Altresco-Pittsfield, 17 DOMSC at 406.

169/ The Siting Council notes that the Pheasant Run apartment complex is located about 1,200 feet from the primary site, and that three residential areas are located within 2,000 feet of the alternative site (Exhs. EPEC-1, Tables 4.12.1, 5.12.1, EPEC-8, p. 3-153).

Engineer (id., Appendix B).

Based on compliance with the above ORDER, the Siting Council finds that the proposed facilities at either the primary site or the alternative site would have acceptable impacts with respect to safety. The Siting Council further finds that the safety impacts of the proposed facility at the primary site and alternative site are comparable.

10. Visual Impacts

EPEC stated that it evaluated the visual impacts of the proposed facility at the primary and alternative sites based on: (1) the character of the visual landscape; (2) the distance of the sites from residences, scenic roadways, recreation sites or worksites, and (3) the number of people within the viewshed of the proposed facility at each site (Exh. EPEC-8, p. 7-9). EPEC asserted that the proposed facility would be more visible from residential areas at the primary site, but also more compatible with its surroundings at the primary site, as compared to the alternative site (EPEC Initial Brief, p. V-83). EPEC argued that its analysis indicates that neither site would provide a clear advantage, and that the sites are essentially equal with respect to visual impact (id.).

EPEC stated that the principal visual elements of the proposed facility would be the HRSG building, with a height of approximately 66 feet, including an approximately 10-foot cylinder on the roof of the building, and the 100-foot high stack (Exh. EPEC-19, p. 2-1; Tr. 8, pp. 54-57). EPEC indicated that, based on its expectation that the proposed facility's air emissions would not result in significant impacts, the proposed stack can be significantly lower that the GEP height of 165 feet without adversely affecting local air quality (Exh. EPEC-19, p. 6-1). In addition, EPEC stated that it would use natural colors for the proposed facility buildings and stack (Exh. EPEC-8, p. 6-7).

EPEC stated that the primary site is industrial in character, and that visual resources in the surrounding area already are significantly altered (id., p. 4-145). Specifically, EPEC stated that the adjacent Foster Forbes complex, with its associated stacks and silos, is a structurally extensive facility that has affected visual aesthetics in the area (id.). EPEC stated that the structures on the Foster Forbes site range from 85 to 125 feet in height (Exh. EPEC-19, Appendix B).

EPEC stated that it evaluated the visual impacts of the proposed facility at the primary site on three viewshed receptors: (1) the Vernon Grove Cemetery, abutting on the west; (2) the Pheasant Run Apartments, 1,200 feet to the northwest; and (3) residences on Howard Street, 1,000 feet to the south (Exh. EPEC-8, pp. 4-149 to 4-150). EPEC stated that the proposed facility would be visible from most portions of the Vernon Grove Cemetery, but would be comparable in height and composition to structures now visible at the Foster Forbes complex (id., p. 4-149). EPEC indicated that an existing hedgerow of evergreen trees would screen the proposed facility from most of the units in the Pheasant Run Apartments, while buildings on the Foster Forbes site and intervening woods would block or limit views of the proposed facility from residences on Howard Street (id.).

In order to mitigate visual impacts on the Vernon Grove Cemetery and the Pheasant Run Apartments, EPEC presented a landscape plan to provide a three-foot high berm and a ten-foot high wooden fence together with arbor vitae, rhododendron and similar plantings along the primary site western boundary, augmenting an existing row of deciduous trees along that boundary (id., p. 6-8, Figure 6.8.1-1; Exh. EPEC-19, p. 3-10).

EPEC has reasonably established that, based on the presence of existing screening by nearby buildings and vegetation and on the proposed implementation of landscaping and fencing on the primary site's western boundary, visual impacts would consist of partial views of the proposed facility, primarily the stack, from the most affected residential receptors. In addition, despite the extent of residential and publicly accessible areas in the vicinity of the primary site, the existing screening ensures that visual impacts of the proposed facility would be non-existent or very limited for many potential viewers. Finally, any visual impacts would be minimized through incorporation of a stack not exceeding 100 feet in height.

Based on the foregoing, the Siting Council finds that use of the primary site for the proposed facility, with the proposed mitigation, would have an acceptable impact on visual resources.

EPEC stated that the 48-acre alternative site is heavily wooded with varied topography, and that views of the site currently are limited by dense forested areas encompassing the parcel (Exh. EPEC-8, p. 3-243). EPEC indicated that possible visual receptors, which may have views of the alternative site, include residences on Beaver Street located as close as 600 feet east of the site, the Birch Street Condominiums located approximately 1,200 feet northwest of the site, and the Birchwood Office Park located northeast of the site (id., pp. 3-218, 3-243, 5-34).

EPEC stated that, given the screening provided by intervening topography and vegetation, visual impacts to the scattered residences located near the alternative site would be insignificant, and would be limited in duration to seasonal leaf-off conditions (id., p. 5-34). EPEC noted that the facility stack would be visible from higher elevations in the area, but did not identify specific locations and impacts (id., p. 7-9).

The proposed facility, sited at the alternative site, would have very limited visibility as a result of existing natural buffers on and off the site. Further, as in the case of the primary site, any visual impacts would be minimized through incorporation of a stack not exceeding 100 feet in height.

Accordingly, the Siting Council finds that use of the alternative site for the proposed facility would have an acceptable impact on visual resources.

EPEC's analysis establishes that location of the proposed facility at the primary site is likely to involve greater visibility, affecting more viewers, than at the alternative site. However, EPEC has established that the existing screening, the proposed landscaping plan, and the relatively low proposed stack height substantially minimize visual impacts for most of the potential viewers at the primary site. Additionally, in contrast to the natural conditions at the alternative site, the presence of existing structures at the adjacent Foster Forbes complex that are of similar scale to the proposed facility serves to further minimize the incremental visual impact of the proposed facility at the primary site.

Accordingly, based on the foregoing and with the proposed mitigation at the primary site, the Siting Council finds that the proposed facility would have a comparable impact on visual resources at the primary and alternative sites.

11. Electric and Magnetic Field Effects

EPEC noted that construction of the proposed generating facility, whether located at the primary site or the alternative site, would require construction of two overhead 115 kV electric transmission lines from the generating facility to the existing NEPCo right-of-way (Exhs. EPEC-8, p. 3-7, HO-RR-79; Tr. 6, pp. 162-163). EPEC stated that its proposed 115 kV transmission lines would produce electric and magnetic fields ("EMF")[170] (Exhs. EPEC-14, EPEC-15). However, EPEC asserted that the potential exposure of Milford residents to EMF presents a negligible health risk (id.; Exh. EPEC-8, pp. 4-151 to 4-160). In support of this assertion, EPEC presented an analysis of EMF levels associated with various distances, which examined three possible construction options for the proposed transmission

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170/ Electric fields and magnetic fields produced by the flow of electricity are collectively known as electromagnetic fields or EMF.

lines (Exh. HO-RR-95).[171]

EPEC indicated that the proposed transmission lines would be located on a 150-foot wide right-of-way at both the primary and the alternative site (Exh. HO-E-23). While EPEC did not specifically measure EMF levels at the edge of that right-of-way, EPEC calculated EMF levels at selected distances ranging from zero to 1,000 feet from the proposed lines (Exh. HO-RR-95). EPEC's calculations included predicted EMF levels at a point 100 feet from the transmission lines -- a point which would be slightly outside the edge of the 150 foot right-of-way (id.). At that point, EPEC's analyses indicated the following maximum EMF levels associated with each of its three identified construction options:

	Maximum Electric Field kilovolts per meter ("kV/m")	Maximum Magnetic Field milligauss ("mG")
Delta	0.095	7.79
Horizontal	0.184	13.01
Vertical	0.039	9.86

EPEC's analysis indicated that EMF levels diminished as a function of distance, i.e., predicted EMF levels were even lower at distances greater than 100 feet from the proposed transmission lines (Exh. HO-RR-95). EPEC's analysis also indicated that EMF levels would remain low regardless of which construction option were to be selected (id.). As a consequence, EPEC stated that its selection of a construction option would be determined by engineering considerations (Exh. HO-RR-96).

In a previous review of proposed transmission facilities which included 345 kV transmission lines, the Siting Council

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171/ EPEC calculated EMF levels using the EXPOCALC computer model under assumed peak loading conditions (Exh. HO-RR-95). With EXPOCALC, EPEC projected the EMF levels associated with three identified options for transmission line design: (1) delta, (2) horizontal, and (3) vertical line configurations (id.).

addressed the expected electric and magnetic field effects of such facilities. Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985) ("1985 MECo Decision"). There, MECo presented testimony which estimated that the electric fields would not exceed 1.8 kV/m and that the magnetic field would not exceed 85 mG along the edge of the right-of-way in Massachusetts. Id. The Siting Council found those edge of right-of-way levels to be acceptable. Id. Further, the Siting Council has applied these edge of right-of-way levels in subsequent reviews of facilities which included 115 kV transmission lines. MASSPOWER, 20 DOMSC at 401-403; Turners Falls, 18 DOMSC at 189-191; 1988 Braintree Decision, 18 DOMSC at 50; 1988 COM/Electric Decision, 17 DOMSC at 328-331; Middleborough Gas and Electric Department, 17 DOMSC at 236-237; NEA, 16 DOMSC at 396-398. Here, the Siting Council notes that the edge of right-of-way EMF levels associated with each of EPEC's three construction options are well below the levels found acceptable in the 1985 MECo Decision.

Accordingly, based on the record, the Siting Council finds that the proposed transmission lines, whether constructed at the primary site or the alternative site, would have acceptable impacts with respect to electric and magnetic field effects. The Siting Council further finds that the primary site and the alternative site are comparable with respect to electric and magnetic field effects.

12. Traffic

In this section, the Siting Council evaluates the traffic impacts of construction and operation of the proposed facility at the primary and alternative sites.

a. Primary Site

EPEC presented estimates of project traffic generation and related traffic impacts during construction and operation of the proposed facility (Exh. EPEC-8, pp. 4-121 to 4-123, 4-130 to 4-134). EPEC asserted that minor traffic impacts would result from construction of the proposed facility, but that no significant traffic impacts would result from operation of the proposed facility (Exhs. EPEC-8, pp. 4-129, 4-134, EPEC-19, pp. 3-8; EPEC Initial Brief, pp. V-56 to V-57).

EPEC indicated that the hours of construction would extend from 7 a.m. to 4 p.m. and that construction-related traffic would encompass 220 vehicle trips per day (Exh. EPEC-8, Table 4.6.1-2, p. 4-123).[172] EPEC further stated that eight employees would work at the plant on a normal workday during operation of the proposed facility (id., p. 4-130). In addition to employee work trips, EPEC stated that operational traffic would include an average of less than one truck per day to deliver supplies and equipment (id.).[173]

EPEC stated that the current peak traffic hours on streets near the primary site are 7:30 a.m. to 8:30 a.m. and 4:45 p.m. to 5:45 p.m. (id., p. 3-168). EPEC noted that it expects the beginning and end of construction work shifts to fall outside the morning and afternoon peak hours (id., p. 4-121). EPEC indicated that the hours of the daytime operational shift, however, would extend from 8:00 a.m. to 4:00 p.m., with the morning shift change occurring during the morning traffic peak and the afternoon shift change occurring before the afternoon traffic peak (id., p. 4-130).

To help quantify the traffic impacts of the proposed facility, EPEC presented a comparison of expected peak hour level of service ("LOS") traffic ratings for three intersections near the primary site, with and without the proposed facility, both during construction and for the first year of operation

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172/ EPEC based its count of vehicle trips per day during construction on an estimated 190 trips by construction employees and 30 trips by construction trucks (Exh. EPEC-8, Table 4.6.1-2, p. 4-123). EPEC estimated that, at peak, a maximum of 210 construction employees would be working at the site (id., p. 4-121).

173/ All the fuel requirements for the proposed facility would be met by natural gas delivered by pipeline (Exh. EPEC-8, p. 4-130).

(id., p. 3-169).[174] EPEC stated that most peak hour LOS ratings at the three intersections would remain unchanged during construction and operation of the proposed facility, and that those ratings that would change during construction and operation would remain at acceptable levels for an urban area (id., pp. 4-129, 4-134). EPEC stated that traffic impacts associated with construction of the proposed facility are expected to be minor and easily accommodated by the key intersections near the primary site (id., p. 4-129). EPEC further stated that the small number of operational employees would not cause significant traffic impacts (id., p. 4-134).

EPEC stated that it would monitor traffic conditions during construction and, if necessary, institute manual traffic control by a police officer (id., p. 6-5). In addition, EPEC stated that the proximity of the primary site to the Conrail railroad line would allow major facility equipment components to be transported by rail, thereby minimizing the need for oversized trucks to use local roads (id., p. 4-138; Exh. EPEC-19, p. 3-8).[175]

EPEC noted that the Town of Milford also has addressed traffic concerns by way of a condition in the Special Permit (see Attachment A) (Exh. EPEC-19, Appendix B).[176] EPEC indicated that the condition limits rail or truck deliveries to

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174/ LOS is expressed by a six-level range identified as A through F (Exh. EPEC-8, p. 3-169). A free traffic flow, with very little delay is designated as LOS A, while a forced flow with excessive backups at traffic signals is designated as LOS F (id.). EPEC indicated that LOS C is a desirable rating, and that during peak traffic times, even LOS D generally is considered acceptable in urban locations (id.).

175/ EPEC stated that since it would only use the railroad for deliveries during construction, there would be no conflict with proposed extension of commuter rail service by the MBTA (Exh. EPEC-8, p. 4-138; Exh. EPEC-19, p. 3-8).

176/ In its decision granting the permit, the Town of Milford Zoning Board of Appeals found that the traffic impacts of the facility, when operational, would be negligible (Exh. EPEC-19, Appendix B, Finding Number 4).

the site to the hours of 7:00 a.m. to 6:00 p.m., and requires truck deliveries that do not originate in Milford to use particular routes, subject to route changes instituted by the Milford Town Engineer (id., Appendix B, Condition 29).[177]

The Siting Council notes that increased vehicular traffic due to construction and operation of the proposed facility at the primary site would not cause significant traffic impacts at key intersections in the vicinity of the primary site. LOS ratings would remain at acceptable levels for an urban area, and the Town of Milford has put restrictions on delivery truck routes and times of travel. The Siting Council expects that EPEC would cooperate with town officials in resolving complaints about truck traffic related to construction or operation of the proposed facility.

Accordingly, based on the foregoing, the Siting Council finds that construction and operation of the proposed facility at the primary site would have an acceptable impact on traffic.

b. Alternative Site

EPEC asserted that the primary traffic impact due to construction of the proposed facility at the alternative site would occur at one intersection near the site during the morning peak hour (Exh. EPEC-8, p. 5-21). EPEC stated, however, that facility operational traffic would not significantly affect traffic flow in the vicinity of the alternative site (id., p. 5-27). In support of these assertions, EPEC presented estimates of project trip generation and related traffic impacts during construction and operation of the proposed facility (id., pp. 5-11 to 5-15, 5-24 to 5-27).

EPEC stated that it performed its analyses of traffic impacts at the alternative site using the same data employed in its analyses of impacts at the primary site for the following

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177/ Tosches expressed opposition to the truck delivery route specified by the Town of Milford (Tosches Initial Brief, p. III-11).

factors: (1) hours of construction-related traffic; (2) number of vehicle trips per day during construction and operation; (3) number of employees during plant operation; (4) number of vehicle trips per day during operation; (5) peak traffic hours; and (6) shift hours of employees during operation of the proposed facility (id., pp. 3-232, 5-15, 5-25).[178] In addition, EPEC presented analyses of traffic at three intersections near the alternative site, using the same LOS methodology described above for the primary site (id., Table 5.1.6-1, p. 5-14).

With respect to construction-related traffic at the alternative site, EPEC stated that the main traffic impact would be a decrease of one LOS rating at one intersection level during the morning peak (id., p. 5-21).[179] EPEC's analysis of the impact of facility operational traffic indicates that, with the exception of traffic entering one intersection from one street during the morning peak, facility operation would not affect prevailing LOS ratings at any of the three intersections (id., p. 5-27). As with the primary site, EPEC stated that it would monitor traffic conditions during construction at the alternative site and, if necessary, institute manual traffic control by a police officer (Exh. EPEC-8, p. 6-6).

The Siting Council notes that increased vehicular traffic due to construction of the proposed facility at the alternative site would temporarily alter LOS ratings at one intersection near the alternative site. Facility operational traffic, however, would affect the LOS rating for only one street. The Siting Council expects that EPEC would cooperate with town

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178/ EPEC stated that it calculated LOS ratings for the alternative site assuming that currently planned reconstruction of one of the intersections would be completed prior to expected peak construction activities at the site (Exh. EPEC-8, p. 5-11).

179/ Existing peak hour levels of service for the intersections studied at the alternative site were generally lower than those at the primary site (Exh. EPEC-8, pp. 3-174, 3-235).

officials in resolving traffic complaints related to construction or operation of the facility at the alternative site.

Accordingly, based on the foregoing, the Siting Council finds that construction and operation of the proposed facility at the alternative site would have an acceptable impact on traffic.

c. Comparison of Traffic Impacts of Primary and Alternative Sites

EPEC argued that the primary site is preferable to the alternative site with respect to traffic because roadways leading to the primary site would experience lesser constraints to capacity than those leading to the alternative site (EPEC Initial Brief, pp. V-79 to V-80). EPEC stated that the ability to deliver equipment to the primary site by rail during construction provided the primary site with a slight advantage over the alternative site in terms of traffic impacts (Tr. 9, p. 92).

The Siting Council notes that operation of the proposed facility would have minor impacts on traffic at either the primary or alternative site, due in part to the minimal amount of truck traffic required for the delivery of supplies. The short-term construction-related impacts on traffic at the alternative site, however, are more significant than those at the primary site since there would be an overall decrease in LOS ratings during the morning peak hour at one intersection near the alternative site. The Siting Council further notes that projected LOS ratings for intersections near the alternative site generally indicate more constricted conditions than those for intersections near the primary site, even without factoring in the effect of construction or operation of the proposed facility. In addition, the Siting Council notes that the proximity of the primary site to the Conrail railroad line provides an advantage over the alternative site because some major facility equipment components would be transported to the primary site by rail, rather than by oversized trucks.

Accordingly, based on the foregoing, the Siting Council finds that the primary site is slightly preferable to the alternative site with respect to traffic impacts.

13. Conclusion on Environmental Impacts

In its analysis of the environmental impacts of the proposed facility at the primary site and the alternative site, the Siting Council has reviewed: (1) water supply; (2) impact of the proposed effluent diversion on waterways; (3) wetlands; (4) air quality; (5) impact on other water users; (6) noise; (7) land use; (8) safety; (9) visual impacts; (10) electric and magnetic field effects; and (11) traffic.

With regard to water supply, the Siting Council has found that the MWC's supply of potable water is adequate to meet the potable water requirements of the proposed facility at either the primary site or the alternative site and that the supply of effluent from the MWTP is adequate to meet the requirements of the proposed facility at either the primary site or the alternative site when streamflow in the upper Charles River is above three cfs.

With regard to the impact of the proposed effluent diversion on waterways, the Siting Council has found that EPEC's analyses of the impact on streamflow, water quality and riverine ecology of the proposed diversion of 1.35 cfs of effluent from the upper Charles River to the proposed project at either the primary site or the alternative site are reliable. The Siting Council has ORDERED EPEC to provide the Siting Council with any modifications to the current MWTP NPDES permit along with an analysis of how EPEC would ensure that operation of the proposed facility does not restrict the ability of the MWTP to comply with any such permit. The Siting Council has found that, based on the compliance with the ORDER in Section III.E.3.c.vii, above, EPEC's analysis of the impact on riverine ecology of the proposed facility at either the primary or the alternative site is reliable. The Siting Council also has found that the proposed project, at either the primary site or the alternative site, would have an acceptable impact on waterways upon compliance with the ORDER set forth in Section III.E.3.c.vii, above.

With regard to wetlands impacts at the primary site, the Siting Council has found that construction of the proposed generating facility at the primary site would have an acceptable impact on wetlands. The Siting Council has ORDERED EPEC to submit to the Siting Council a determination from the affected conservation commissions and/or from the MDEP of the applicability of the WPA to the wetlands impact resulting from the proposed effluent diversion. The Siting Council has found that EPEC's preferred effluent line route to the primary site, if constructed simultaneously with the sewer intercept would have an acceptable impact on wetlands. The Siting Council has further ORDERED EPEC to locate the transmission line poles to the primary site outside the Godfrey Brook wetland area, and to locate any access roads in a manner which avoids wetland alteration. Based on compliance with the above ORDER, the Siting Council has found that construction of the proposed electric transmission line for the primary site would have an acceptable impact on wetlands. Finally, the Siting Council also has found that construction of the sewer line, the natural gas pipeline and the natural gas meter station for the primary site would have an acceptable impact on wetlands.

With regard to wetlands impacts at the alternative site, the Siting Council has found that construction of the generating facility, effluent line, electric transmission line, sewer line and natural gas pipeline would have an acceptable impact on wetlands. The Siting Council also has found that the primary site is preferable to the alternative site with respect to wetlands.

With respect to air quality, the Siting Council has found that the stack emission of the proposed project at the primary site and the alternative site would have an acceptable impact on air quality. The Siting Council has made no finding whether the impact on air quality of the stack emissions are preferable at the primary site or the alternative site. The Siting Council also has found that operation of the proposed cooling tower would have acceptable air quality impacts at the primary site or the alternative site, and that the primary site and the alternative site are comparable with respect to air quality impacts of the proposed cooling tower.

With regard to the impact on other water users, the Siting Council has ORDERED EPEC to submit to the Siting Council the approved SPCC, Stormwater Control and Discharge Plan, and the groundwater analysis plan, as specified in the Town of Milford Special Permit. The Siting Council further has ORDERED EPEC to immediately notify the Siting Council and MDEP of any changes in groundwater flow patterns in the primary recharge area of the Godfrey Brook wellfield due to operation of the proposed facility and to submit plans to MDEP to remedy any adverse impact on groundwater resulting from operation of the proposed facility. Based on compliance with the above ORDERS, the Siting Council has found that construction and operation of the proposed project at the primary site would have an acceptable impact on other water users. The Siting Council also has found that construction and operation of the proposed project at the alternative site would have an acceptable impact on other water users. Finally, the Siting Council has found that the alternative site is slightly preferable to the primary site with respect to impacts on other water users.

With regard to noise, the Siting Council has found that the proposed facility would have an acceptable impact on community noise levels at the primary site or at the alternative site. The Siting Council additionally has found that the primary site is preferable to the alternative site with respect to noise impacts.

With regard to land use, the Siting Council has found that the primary site and the alternative site would have an acceptable impact. The Siting Council also has found that the primary site is preferable to the alternative site with respect to land use.

With regard safety, the Siting Council has ORDERED EPEC to demonstrate that it has included mitigation measures, such as enclosed containers, in its facility design which ensure that ammonia concentrations would not exceed 500 ppm at the site boundary under worst case conditions of ammonia release, or, in the alternative, to perform a dispersion modeling analysis which demonstrates that an off-site limit of 500 ppm will not be exceeded under worst case conditions with the mitigation measures currently incorporated in the proposed facility design. The Siting Council has found that, based on compliance with the above ORDER, the proposed facility at the primary site or the alternative site would have acceptable impacts with regard to safety. The Siting Council also has found that safety impacts at the proposed and alternative sites are comparable.

With regard to visual impacts, the Siting Council has found that use of the primary site or the alternative site would have an acceptable impact on visual resources and that the primary site and the alternative site are comparable with regard to visual impacts.

With regard to electric and magnetic field effects, the Siting Council has found that construction of the proposed project at either the primary site or the alternative site would have acceptable impacts with respect to electric and magnetic field effects, and that the primary site and the alternative site are comparable with respect to electric and magnetic field effects.

With regard to traffic, the Siting Council has found that construction and operation of the proposed facility at the primary site or the alternative site would have an acceptable impact on traffic, and that the primary site is slightly preferable to the alternative site with respect to traffic impacts.

In sum, the Siting Council finds that construction of the proposed project at the primary site or the alternative site, based on compliance with the ORDERS set forth above, would be acceptable with regard to environmental impacts.

The Siting Council has found that the primary site and the alternative site are comparable with regard to water supply, impact on waterways, impact of cooling tower emissions on air quality, safety, visual impacts, and electric and magnetic field effects. The Siting Council also has found that the primary site is preferable to the alternative site with regard to wetlands impacts, noise impacts, land use and traffic. The Siting Council further has found that the alternative site is slightly preferable to the primary site with regard to impact on other water users due to the location of the primary site on the primary recharge area for the Godfrey Brook wellfield. However, the Siting Council also has found that EPEC has adequately minimized the risk of potential contamination of the Godfrey Brook wellfield.

Accordingly, based on the foregoing, the Siting Council finds that construction of the proposed project at the primary site is preferable to construction of the proposed project at the alternative site with regard to environmental impacts.

The Siting Council further notes that the Town of Milford has conducted a comprehensive review of the proposed project through its Special Permit process described in Section III.E.6.a, above, and that the Special Permit which resulted from this process includes 56 conditions which direct EPEC to take a number of steps to minimize the environmental impacts associated with construction and operation of the proposed facility at the primary site. Accordingly, the Siting Council ORDERS EPEC to comply fully with the conditions set forth in the Special Permit issued by the Town of Milford.
from this process includes 56 conditions which direct EPEC to take a number of steps to minimize the environmental impacts associated with construction and operation of the proposed facility at the primary site. Accordingly, the Siting Council ORDERS EPEC to comply fully with the conditions set forth in the Special Permit issued by the Town of Milford.

F. Reliability Analysis of the Proposed and Alternative Facilities

In this section the Siting Council examines the reliability of EPEC's proposed project at the primary and alternative sites. Specifically, the Siting Council evaluates the reliability impacts of EPEC's contingency plan for mitigating the potential environmental impacts associated with the use of effluent from the MWTP for cooling purposes.

EPEC's proposed facility incorporates the use of a wet cooling technology[180] to condense the steam exiting from the steam turbine. As noted in Section III.E.2.b, above, effluent from the MWTP is proposed for use in the wet cooling system at either the primary or alternative site. EPEC stated, however, that unmitigated use of the effluent during certain periods of the year could lead to unacceptable impacts to the upper Charles River (Exh. EPEC-19, p. 5-1). Therefore, in order to avoid such impacts, EPEC stated that it would reduce or cease its diversion of effluent whenever such diversions would result in a streamflow of three cfs or less in the upper Charles River

180/ EPEC explained that its wet cooling system consists of a cooling tower and a condenser (Exh. EPEC-19, p. 5-3). EPEC explained that in its wet cooling system, steam is condensed in the condenser by passing it over pipes filled with cold cooling water (id., p. 2-15). The cooling water is pumped from the condenser pipes to the top of the cooling tower and sprayed onto a porous "fill" where it is cooled with air drawn through it by a fan at the top of the tower. The cooling water which is not lost in the cooling tower through evaporation is collected in a basin at the bottom of the tower, and pumped back into the condenser (id.). The wet cooling system proposed would require an average of 709 gallons per minute ("gpm") of "makeup" water from the MWTP to replace evaporative losses (six gpm of potable water would also be used for makeup) (id., Figure 2.2.3-1). EPEC stated that an average of 135 gpm of the makeup water would be returned to the MWTP as part of EPEC's wastewater stream, resulting in an average evaporative loss of 580 gpm (id.). EPEC also stated that the peak makeup water requirement to offset evaporative loss would be 639 gpm (id., p. 5-7). EPEC noted that plant cooling water consumption is dependant on power output, which is in turn dependent, in part, on ambient temperature (Exh. HO-E-5).

(*id.*).[181] Specifically, EPEC identified a series of contingency measures including purchases of potable water for use in cooling and modifying plant operations, which it intends to implement to ensure that unacceptable impacts to the upper Charles River do not occur.

EPEC identified its proposed contingency plan for low streamflow conditions as consisting of implementation of the following measures: (1) a measurement system to monitor and record the streamflow of the upper Charles River; (2) use of potable water from an on-site 500,000 gallon storage tank;[182] (3) provisions to increase purchases of potable water from the MWC; and (4) modifying plant operations to reduce cooling requirements when insufficient potable water is available (Exh. EPEC-19, p. 5-4 to 5-6). EPEC stated that the streamflow monitoring system would provide EPEC with streamflow data on an almost instantaneous basis (*id.*).[183] EPEC stated that, within two hours of detection of streamflow levels below three cfs, the effluent diversion would be scaled down to allow streamflow levels to return to three cfs (*id.*). To compensate for the reduction in effluent available for use as cooling water, EPEC stated that it would use potable water from its storage tank in combination with purchases of additional potable water from the MWC (*id.*).[184] EPEC also stated that water consumption within

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181/ See Section III.E.3, above for a discussion and analysis of the impacts of maintaining the three cfs minimum streamflow in the upper Charles River.

182/ EPEC noted that additional storage could be added in the future if necessary (Exh. EPEC-19, p. 7-2). EPEC further stated that stored potable water would be replenished via interruptible purchases from MWC (*id.*, p. 5-6).

183/ EPEC stated that the gauge for its streamflow monitoring system would be located downstream of the MWTP at either the Conrail or the Howard Street crossings of the Charles River (Exh. EPEC-19, p. 5-6).

184/ EPEC noted that some effluent likely would be available during many of the anticipated low flow events, thereby reducing the need to rely solely on storage volumes and additional purchases of potable water (Exh. EPEC-19, p. 7-2).

the facility could be scaled down through drawdown of the cooling tower basins or reduction in power output (id.).[185] Finally, in the event that insufficient potable water is available to meet reduced facility water needs, EPEC stated that the facility would be shut down (id.).

EPEC stated that, as a result of its diversion of effluent from the MWTP for use in its cooling system, the average frequency of low flow conditions of three cfs or less in the upper Charles River would increase from approximately 0.1 percent to approximately six percent annually[186] (see Figure 3) (Exh. EPEC-19, p. 5-4). Thus, EPEC expects to implement its contingency plan, on average, for approximately six percent of the year. As described in Section III.E.2.b, above, EPEC presented studies which indicate that, with maximum effluent diversion levels, the majority of low flow events would likely occur in August and September.[187] EPEC stated that its

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185/ EPEC stated that with a reduction in available effluent of 15 percent (106 gpm) it would be able to continue normal operation with the use of stored water for over 122 hours, after which the facility could be operated indefinitely at a reduced power output of 104.2 MW until full effluent diversion could be resumed or alternative supplies were made available (Exh. HO-RR-73). Similarly, EPEC stated that with a reduction in available effluent of 23 percent (167 gpm), normal operation could be maintained with the use of stored water for over 49 hours, after which the facility could be operated indefinitely at a reduced power output of 81.5 MW until full effluent diversion could be resumed or alternative supplies were made available (id.).

186/ EPEC stated that low flow events typically would last only a few hours with some regularity in early morning periods during summer months (Exh. EPEC-19, p. 7-2). EPEC noted that longer low flow events lasting days were expected to occur much less frequently (id.). EPEC stated that it would implement its contingency plan for low flow events of both short and long duration (id.).

187/ EPEC's studies indicate that low flow events could occur on an average of 3.4 percent of July days, 22 percent of August days, 21.2 percent of September days, 8.7 percent of October days and 2.2 percent of November days (Exh. HO-RR-58, Table 4.2.1-2, Revised).

facility operation plan calls for the proposed facility to be shut down for two weeks each year in September for annual maintenance activities (id., p. 5-6 to 5-7). EPEC further stated that it would attempt to coordinate its planned maintenance shutdown in September with anticipated periods of low flow in that month, thereby eliminating the need to implement its contingency plan on those days (id.).

Further, EPEC asserted that operation of its proposed facility with the planned contingency measures would not affect facility availability to any significant degree (Exh. HO-70). EPEC indicated that the proposed facility would have to shutdown only infrequently as the result of insufficient water supplies, and therefore, overall plant availability would not be unacceptably affected (Exh. HO-RR-70). EPEC noted that a 90 percent availability factor is required under the NEPCo contract to avoid paying penalities (id.). EPEC also noted that, while it assumed a 92.5 percent availability factor for financial modeling purposes,[188] the experience of EPEC's affiliates with identical gas turbines and similar boilers has been to achieve 96 percent availability factors annually (id.). Finally, EPEC noted that its debt coverage studies indicate that minimum debt coverage can be achieved with availability factors as low as 79 percent (id.).

EPEC argued that its intended reliance on the MWC for additional potable water supplies during low flow events would not burden the MWC unduly or jeopardize the area's water supply (EPEC Initial Brief, p. V-93). EPEC stated that the recent drop in local potable water demand had generated additional room to

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188/ EPEC analyzed what it considered to be a worst case financial scenario of a three percent reduction in plant availability (from 92.5 percent to 89.5 percent) associated with full shutdown of the project due to lack of adequate cooling water supplies (Exh. HO-RR-70). EPEC stated that under this scenario, the project would suffer a 15 percent reduction in its net present value (the level of income generated over and above the cost of borrowed funds), and an eight percent drop in the internal rate of return on the owner's investment (id.; Exh. HO-RR-71).

supply the occasional, emergency needs of the proposed facility under its contingency plan, and that these additional supplies would be purchased on an interruptible basis and, therefore, would not affect the MWC's ability to meet its other water demands (id., p. V-42). See Section III.E.2.a, above for a further discussion of the MWC potable water supply. Finally, EPEC noted that MWTP flow has increased over time and is expected to continue to increase in the future due to increases in demand for MWC water (Tr. 4, p. 95). EPEC argued that, as increases in MWC water demand result in increases in MWTP effluent discharges, the need to substitute MWC water for MWTP effluent will be reduced (EPEC Initial Brief, p. V-42).

Bellingham argued that EPEC has not demonstrated that potable water supplies will be available when needed to replace effluent (Bellingham Initial Brief, p. 9). CRWA similarly argued that EPEC has not adequately demonstrated how the proposed facility would cope with extended dry periods and potential shortages of potable water while continuing to honor its power contracts (CRWA Initial Brief, pp. 13-15).

EPEC's choice of cooling technology necessitates the use of contingency measures, potentially including shutdown of the plant, to ensure acceptable environmental impacts. The implementation of these contingency measures has the potential to affect the reliability of the facility's power output. Further, the time periods during the year associated with the potential need to implement these contingency measures generally coincide with annual periods of peak electrical load when reliable output from the facility is most critical. EPEC has recognized these issues and has presented a comprehensive plan for mitigating potential reliability impacts. The Siting Council agrees with Bellingham and CRWA that EPEC's analysis does not conclusively establish that sufficient potable water supplies will be available to the facility in every instance where such supplies are needed to supplement or completely replace the use of effluent for cooling purposes. However, the Siting Council recognizes that such conclusive evidence is not available due to the irregular nature of the low flow events in terms of occurrence, duration, and severity.

EPEC's analyses show that, on average, low-flow events would require implementation of the contingency plan six percent of the year. The record clearly demonstrates, however, that this does not mean that for six percent of the year EPEC would be forced to purchase its full cooling water needs from the MWC or face plant shutdown. The Siting Council notes that a significant portion of the low flow events included in this six percent annual period are likely to be of short duration or of insufficient severity to require total cessation of effluent diversion. Thus, EPEC's ability to augment its use of effluent through the use of stored water which can be replenished routinely provides a significant buffer against potential reliability impacts from low flow circumstances. In essence, low flow periods of significant duration or severity become the issue of concern rather than the total frequency of low flow events. The Siting Council notes that such severe low flow events likely could be forseen. Thus, as approximately one third of all low flow occurrences are expected to take place during September, EPEC likely would be able to schedule its two week routine maintenance period to coincide with anticipated severe low flow periods during that month, thereby reducing further the potential reliability impacts associated with low flow circumstances.

The Siting Council also notes that the record indicates that currently permitted, non-emergency MWC water supplies are sufficiently in excess of current water demand to reasonably ensure that EPEC would be able to purchase adequate supplies to maintain plant operation even in the event of the total cessation of all effluent diversions. In addition, future increases in effluent due to increases in local MWC water use should reduce the size and frequency of necessary reductions in effluent diversions.

EPEC's NEPCo contract includes penalties if the plant is not able to achieve a 90 percent availability level. While the

Siting Council is concerned with any reduction in plant availability, we recognize that, from the perspective of the reliability of the power systems of the purchasing utilities, it is appropriate to consider a contracted availability level as indicative of an acceptable reliability level. Here, EPEC has demonstrated that it is unlikely that implementation of its contingency plan in the event of low streamflows in the upper Charles River would lead to plant shutdowns with sufficient frequency to reduce overall annual plant availability to a level below 90 percent. In addition, EPEC has demonstrated that the potential reduced plant availability would not adversely impact project viability.

Accordingly, the Siting Council finds that EPEC has established that operation of the proposed facilities, incorporating implementation of the proposed low streamflow contingency plan as necessary, at either the primary or alternative site, would have an acceptable impact on facility reliability. In addition, the Siting Council finds that the primary and alternative sites are comparable with respect to reliability.

G. Comparison of Primary and Alternative Sites

The Siting Council has found that EPEC has considered a reasonable range of practical facility siting alternatives. The Siting Council also has found that the costs of construction and operation of the proposed facilities at the primary or alternative site would be realistic for a facility of the size and design of the proposed facilities. In addition, the Siting Council has found that the construction and operation of the proposed facilities at the primary or alternative site would have (1) acceptable environmental impacts and (2) an acceptable impact on facility reliability. Further, the Siting Council has found that the construction and operation of the proposed facilities at the primary site would be preferable from the perspective of both costs and environmental impacts to the construction and operation of the proposed facilities at the alternative site. Finally, the Siting Council has found that the primary and alternative sites are comparable with respect to reliability.

Accordingly, the Siting Council finds that the primary site for the proposed facility is superior to the alternative site in terms of cost, environmental impacts, and reliability.

In its review of proposed facilities, the Siting Council must ensure that the costs, environmental impacts and reliability of such facilities are acceptable. In addition, however, the Siting Council has an obligation to ensure that the costs and environmental impacts of the proposed facilities are adequately minimized consistent with ensuring reliable supply.

In this proceeding, due to the environmental and reliability issues associated with EPEC's proposed use of wet cooling technology, the issue has been raised as to whether the facility, as proposed, achieves the best balance among costs, environmental impacts and reliability. In order to ensure that the facility achieves the appropriate balance among these criteria, the Siting Council must evaluate whether EPEC's chosen cooling technology is preferable to alternative cooling technologies.

H. Alternative Mitigation Strategy: Cooling Technologies

Few issues in this proceeding have been the subject of as much documentation and testimony as the potential impact of EPEC's use of MWTP effluent for cooling purposes on the upper Charles River. The use of this effluent is driven by EPEC's use of a wet cooling technology, and requires EPEC to develop a contingency plan for plant operations to mitigate potential impacts to the upper Charles River.[189] While EPEC has established that construction and operation of its proposed

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189/ See Section III.E.3, above, for a discussion of the environmental impacts of the proposed effluent diversion and contingency plan, and Section III.F, above, for a discussion of the reliability impacts of the proposed contingency plan.

facilities with the proposed contingency measures would successfully mitigate potential environmental impacts,[190] and would have an acceptable impact on facility reliability, the question of whether an alternative mitigation strategy, i.e., use of an alternative cooling technology, would better achieve the balance between minimizing environmental impacts and cost and achieving reliability must be addressed before the Siting Council can find that the proposed facilities meet our standard for ensuring a necessary energy supply at the least cost and the least environmental impact.

EPEC stated that it considered a variety of alternative cooling technologies as an alternative mitigation strategy to the development of its contingency plan (Exh. EPEC-19, p. 5-1). Specifically, EPEC stated that it considered the use of a dry condenser cooling system, two different wet/dry hybrid cooling systems, and a wet surface air cooled ("WSAC") cooling system as alternatives to the use of its wet cooling system and contingency plan (id., pp. 5-7 to 5-10). EPEC argued that its proposed cooling system and contingency plan were preferable to each of the alternative cooling technologies considered by EPEC on the basis of balancing cost, environmental impact and reliability (id.; EPEC Initial Brief, p. V-85). The Siting Council reviews EPEC's analyses of the alternative cooling technologies below.

1. Description

a. Wet Cooling

EPEC stated that its proposed wet cooling system has been designed to maximize the efficiency of the power generation process, thereby reducing associated fuel usage and air

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190/ In Section III.E.3.d, above, the Siting Council found that, upon compliance by EPEC with the ORDER contained in Section III.E.3.c.vii, above, relating to the resource monitoring, assessment and mitigation plan to be signed between EPEC and the MDEP, EPEC's proposed facility would have an acceptable impact on waterways at either the primary site or the alternative site.

emissions (Exh. EPEC-19, pp. 5-2 to 5-4, 5-7). EPEC further noted that its proposed wet cooling system will maximize the efficiency of its use of effluent through multiple cooling cycles (Exh. HO-E-6).[191]

In regard to the environmental impacts of the proposed wet cooling system, EPEC stated that the system would require an average of six gpm of potable water and 709 gpm of makeup water from the MWTP, of which an average of 580 gpm would be lost due to evaporation (Exh. EPEC-19, Figure 2.2.3-1). Further, EPEC stated that the peak evaporative loss associated with its wet cooling system would be 639 gpm (id.). EPEC stated that the balance of the cooling water not lost to evaporation (approximately 22 percent) would be returned to the MWTP as part of the facility's wastewater stream (id.). EPEC further indicated that the proposed wet cooling system would require 4,800 square feet of land, would result in noise impacts of 41 dBA at 1300 feet with no obstructions, and would be 50 feet tall (id., Table 5.9.1-1). Finally, EPEC noted that use of the proposed wet cooling system would require implementation of its contingency plan for an average of six percent of the year (id., p. 5-11).[192]

In regard to cost,[193] EPEC indicated that the total

191/ For a further description of EPEC's wet cooling system, see Section III.F, above.

192/ For a further description of EPEC's contingency plan and its potential impact on facility reliability, see Section III.F, above.

193/ The Siting Council notes that EPEC provided information regarding the various cooling technologies throughout the proceeding in response to information requests, record requests and in testimony. In addition, EPEC provided a detailed cost analysis of the alternative cooling technologies in its FEIR (Exh. EPEC-19). The Siting Council notes that the cost information presented in EPEC's data responses and testimony is poorly documented and, in some cases, inconsistent with the data presented in the FEIR. Therefore, the Siting Council considers the cost information contained in the FEIR in its review of the cooling systems as this data is more recent, more comprehensive and better documented than the other cost information contained in the record.

capital costs of its proposed wet cooling system would be approximately $5.1 million, including $3.2 million in total direct costs ("TDC"), resulting in an annualized cost over 15 years of approximately $743,000 (id., Table 5.9.3-2).[194] EPEC estimated annual O&M costs for its proposed wet cooling system to be approximately $1.1 million (id., Table 5.9.3-3).[195, 196]

b. Dry Cooling

EPEC explained that the dry cooling system that it considered condenses the steam exiting the steam turbine by passing it through a series of finned tubes in a cooling tower (id., p. 5-7, Figure 5.7.1-1). A fan at the top of the cooling tower draws air over the finned tubes, thereby cooling and condensing the steam inside (id., p. 5-7). The condensate then

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194/ EPEC stated that in its calculation of the capital costs of the cooling systems it included the following cost items: (1) TDC, which includes purchased equipment and direct installation costs at 30 percent of purchased equipment costs; (2) indirect installation costs at 38 percent of TDC; (3) startup and performance testing costs at one percent of TDC; (4) working capital at 30 days of O&M costs for each system; and (5) interest during construction at 12 percent (Exh. EPEC-19, Table 5.9.3-2). EPEC stated that it based its cost estimates on vendor pricing information for cooling systems with comparable system design parameters (id., p. 5-13, 5-17, Table 5.9.1-1, Table, 5.9.2-1). EPEC noted that it based its capital cost estimation methodology on the 1990 Control Cost Manual prepared by the US EPA's Office of Air Quality Planning and Standards (id., p. 5-17, 5-19, Table 5.9.2-1).

195/ EPEC stated that in calculating the O&M costs of the cooling systems, it considered maintenance costs (calculated at five percent of TDC), raw material costs, electricity costs, overhead, property tax, insurance costs, administration costs, capacity penalties, and mitigation costs (Exh. EPEC-19, pp. 5-19 to 5-21, Table 5.9.2-2, Table 5.9.3-3).

196/ In developing its O&M cost estimate for its proposed wet cooling system, EPEC assumed use of potable water for total cooling needs for the full six percent of the year during which implementation of the contingency plan would be required on average. Due to the $1.65 cost difference per 1000 gallons of potable water relative to effluent, this resulted in an approximately $38,000 additional annual cost for cooling water due to mitigation (Exh. EPEC-19, Table 5.9.3-3).

is pumped back to the HRSG for re-use (id.). EPEC further stated that a dry cooling system cannot cool the turbine exhaust steam as efficiently as a wet cooling system, resulting in an inherent decrease in overall plant efficiency (id.).[197] EPEC noted that this decrease in plant efficiency would lead to a reduction in plant output of 3.5 MW (Exh. HO-E-5). EPEC further noted that this reduced efficiency, combined with the high costs of such dry cooling systems, typically results in their use only in areas where no cooling water is available (Exh. EPEC-19, p. 5-7).

In regard to the environmental impacts of the alternative dry cooling system, EPEC stated that the dry cooling system would not require any makeup water from the MWTP (id., p. 5-7). EPEC further indicated that the alternative dry cooling system would require 11,500 square feet of land, would result in noise impacts of 42 dBA at 1,300 feet with no obstructions, and would be 65 feet tall (id., Table 5.9.1-1).[198, 199] Finally, EPEC

197/ EPEC stated that due to the increase in heat rate associated with dry cooling system, fuel consumption would be increased by up to 770 mcf per day relative to operation with the wet cooling system (Exh. EPEC-19, p. 5-12).

198/ EPEC originally stated that it did not believe that the dry cooling system could be accommodated on the primary site (Tr. 6, pp. 52, 56, 60-62). However, the record indicates that, due to relocation of the stormwater detention basin to the northern portion of the primary site, which was acquired by EPEC during the course of this proceeding, there appears to be sufficient room available at the primary site to accommodate dry cooling technology (Exh. EPEC-19, Figure 2.2.2-1). Therefore, the Siting Council assumes for the purposes of this review that EPEC could install the dry cooling system at either the primary or alternative sites.

199/ EPEC originally stated that use of the dry cooling system would result in undesirable noise impacts (Exh. HO-E-5). In its FEIR, however, EPEC indicated that noise levels could be reduced from 55 dBA to 42 dBA at 1300 feet through the use of "super low noise" fans (Exh. EPEC-19, Table, 5.9.1-1). EPEC noted, however, that the "super low noise" fan is a new technology which has yet to be commercially proven in such systems (id., p. 5-30).

noted that use of the alternative dry cooling system would not require implementation of its contingency plan for mitigating impacts to the upper Charles River (id., p. 5-30).

In regard to cost, EPEC indicated that the total capital costs of the alternative dry cooling system would be approximately $11.7 million, including $7.4 million for TDC, resulting in an annualized cost over 15 years of approximately $1.7 million (id., Table 5.9.3-2). EPEC estimated annual O&M costs for the alternative dry cooling system to be approximately $3.0 million (id., Table 5.9.3-3).[200]

c. Wet/Dry Hybrid Cooling

EPEC explained that the two wet/dry hybrid cooling systems that it considered combine a dry cooling tower with a wet cooling tower and condenser (id., p. 5-7, 5-10, Figure 5.7.2-1). EPEC stated that such systems have the advantage relative to dry cooling systems of maintaining plant efficiency levels comparable to wet systems (id., p. 5-7). EPEC indicated that it considered two systems, one with a peak makeup water requirement of 250 gpm, and the other with a peak makeup water requirement of 420 gpm (id., Table 5.9.1-1). EPEC further indicated that the two alternative wet/dry cooling systems would require 24,000 square feet and 13,000 square feet of land, respectively, would result in noise impacts of 43 dBA and 42 dBA, respectively, at 1,300 feet with no obstructions, and would be 81 feet and 50 feet tall, respectively (Exh. EPEC-19, Table 5.9.1-1). EPEC noted that, despite the decreased water requirements of the wet/dry cooling systems, these systems still would require implementation of a contingency plan during low

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200/ EPEC included $1.1 million in annual economic penalities in its estimation of O&M costs for the dry cooling system (Exh. EPEC-19, Table 5.9.3-3). EPEC asserted that these costs would be incurred because, under the terms of its PPA, the MW output of the plant at 90 degrees Fahrenheit (approximately 3.5 MW less than the output using the wet cooling system) determines the plant capacity rating which is, in turn, used to develop capacity revenue charges (id., p. 5-21).

flow conditions (id., pp. 5-7, 5-10). Specifically, EPEC stated that use of the wet/dry cooling system with a peak water requirement of 250 gpm would result in low flow events approximately two percent of the year, while use of the wet/dry cooling system with a peak water requirement of 420 gpm would result in low flow events approximately four percent of the year (id., p. 5-11).

In regard to cost, EPEC indicated that the total capital costs of the two wet/dry cooling systems would be approximately $26.4 million and $16.6 million, respectively, for the 250 gpm and 420 gpm systems (id., Table 5.9.3-2). These costs include $15.8 million and $9.9 million, respectively, for TDC, resulting in an annualized cost over 15 years of approximately $3.9 million and $2.4 million, respectively (id.). EPEC estimated annual O&M costs for the two wet/dry cooling systems at approximately $3.5 million and $2.4 million, respectively, (id., Table 5.9.3-3).

d. WSAC Cooling

EPEC described the WSAC system that it considered as a dry cooling system that has its performance augmented by cascading water over the fins of the tubes (id., p. 5-10). EPEC stated that the WSAC cools steam as effectively as the proposed wet cooling system (id.). EPEC also noted that the WSAC system has a lower average water requirement than the wet cooling system, but that it has a peak makeup water requirement of 724 gpm (id., Table 5.9.1-1). EPEC noted that the WSAC system is based on a technology with little actual operating experience in applications which utilize wastewater effluent, raising the question of whether MWTP effluent would be of sufficient quality for use in a WSAC system (id., p. 5-10).[201] EPEC further indicated that the WSAC cooling system would require 9,000 square feet of land, would result in noise impacts of 41 dBA at 1,300 feet with no obstructions, and would be 30 feet tall (Exh. EPEC-19, Table 5.9.1-1). EPEC noted that the makeup water requirements of the WSAC system are driven by the same evaporative rate as the proposed wet cooling system (id., p. 5-10). Thus, EPEC stated that this system would require the same level of mitigation as the proposed wet cooling system through implementation of a contingency plan an average of six percent of the year (id.).

In regard to cost, EPEC indicated that the total capital costs of the WSAC cooling system would be approximately $5.8 million, including $3.4 million for TDC, resulting in an annualized cost over 15 years of approximately $846,000 (id., Table 5.9.3-2). EPEC estimated annual O&M costs for the WSAC cooling system at approximately $968,000 (id., Table 5.9.3-3).

In conclusion, based on its analyses, EPEC stated that the dry cooling system and the two wet/dry cooling systems are not economically viable options for the proposed facility as they would result in increases in annual costs relative to the wet cooling system which would be greater than the annual profit

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201/ EPEC stated that WSAC cooling systems raise a significant reliability concern because they are an emerging technology with little actual operating experience in applications which utilize wastewater effluent (Exh. EPEC-19, p. 5-10). Specifically, EPEC stated that the finned heat transfer surface of a dry condenser, over which water is cascaded in the WSAC system is susceptible to fouling and corrosion from the dissolved salts which would be expected to plate out during evaporation of the effluent (id.). EPEC stated that such fouling and corrosion could lead to operating efficiency loss, the need for periodic shutdown for cleaning, and the potential need to utilize expensive corrosion resistant materials (id.).

potential of the project (id., p. 5-31).[202] EPEC further stated that the WSAC cooling system offers no advantage relative to the wet cooling system in terms of water use and presents potentially severe reliability concerns related to the use of effluent (id.). Therefore, EPEC asserted that its proposed wet cooling system is superior to the alternatives (id.).

CRWA argued that EPEC's original cost analyses of the alternative cooling technologies were incomplete and did not support EPEC's claim of cost superiority for its wet cooling technology (CRWA Initial Brief, pp. 7-8).[203]

2. Analysis

The Siting Council notes that EPEC has presented a comprehensive analysis of the alternative cooling technologies in its FEIR. The Siting Council also notes that EPEC's analysis, as contained in the FEIR, is generally supported by an appropriate level of vendor data, is consistent in its use of

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202/ During the course of the proceeding, EPEC provided financial analyses of the impact on project viability associated with use of the various alternative cooling systems (Exhs. HO-E-5, HO-RR-67, HO-RR-71). The Siting Council notes that these analyses were based on the cost data contained in the record at that time, and therefore, are not directly relevant to this discussion. Nevertheless, these analyses show that, with the costs assumptions used, both the dry cooling system and the wet/dry cooling systems would have a significant impact on the project's internal rate of return and net present value (id.). The Siting Council also notes that the costs of the alternative cooling technologies on which these analyses were based were generally comparable to those contained in the FEIR, except in the case of annual O&M costs for the dry cooling system which, apparently, contained no capacity penalty costs, and were estimated to be approximately $300,000 less than the annual O&M costs for the wet cooling system (id.).

203/ The Siting Council notes that the briefing period in this proceeding preceded the issuance of the FEIR with the updated cost information addressed here. The Siting Council agrees with CRWA that EPEC's original cost analyses of the alternative cooling technologies were incomplete and inconsistent. However, the Siting Council notes that the analyses contained in the FEIR address many of these apparent flaws.

underlying assumptions, and is appropriately broad in its consideration of impacts and costs. Further, the Siting Council notes that the overall cost estimation methodology used by EPEC is appropriate for analyses of this type.[204]

With regard to the WSAC cooling technology, the Siting Council concurs with EPEC that the system offers no benefit from the perspective of water use. Further, the land use requirements, noise impacts, visual impacts, costs and efficiency of the WSAC cooling system are comparable to those associated with the wet cooling system. Therefore, as a result of the potential operational problems associated with use of effluent in the WSAC system, the Siting Council finds that the wet cooling system is preferable to the WSAC system on the basis of balancing cost, environmental impacts and reliability.

With regard to the three remaining systems considered, the dry cooling system and the two wet/dry cooling systems, the record indicates that, while the wet/dry systems would provide more efficient cooling than the dry cooling system, they still would require significant quantities of cooling water. Further, the wet/dry technologies require the most land of all the technologies considered and are comparable to the dry cooling technology with respect to noise and visual impacts. Therefore, the Siting Council finds that the dry cooling system is preferable to the two wet/dry cooling systems with respect to environmental impacts. Further, the two wet/dry cooling systems are either comparable to or considerably more expensive than the dry cooling technology. In addition, the wet/dry system which is comparable to the dry system in terms of cost has the higher

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204/ The Siting Council also notes, however, that, had the FEIR not been included in the record of this proceeding, our ability to adequately assess EPEC's decision to use the proposed wet cooling system would have been compromised. Project proponents must provide comprehensive and well documented supporting analyses in order for the Siting Council to determine if their facility design appropriately balances cost, environmental impacts and reliability.

water requirements. Therefore, the Siting Council finds that the dry cooling system would be preferable to use of either of the wet/dry cooling systems on the basis of balancing cost, environmental impacts and reliability.

With respect to the relative impacts and costs of the dry cooling system and wet cooling system, the Siting Council first notes the reduction in overall plant efficiency associated with the dry cooling system. While this is reflected in the cost comparison of the two systems, the Siting Council is concerned from a broader perspective with the efficient use of fossil fuels for energy production as a result of the direct impact of efficiency on both the cost and environmental impacts associated with power generation through fossil fuel combustion. The Siting Council notes that it is clearly desirable to maximize the efficiency of fuel use where possible, consistent with environmental impacts and costs.

With regard to environmental impacts, the record indicates that the visual and noise impacts of the dry cooling system essentially would be comparable to those of the wet cooling system. EPEC further indicated that the dry cooling system would require over twice as much land as the wet cooling system. While the wet cooling system therefore would be preferable to the dry cooling system with respect to land use, the Siting Council finds that the significant difference in water requirements (an average evaporative loss of 580 gpm for the wet cooling system versus no water requirement for the dry cooling system) makes the dry cooling system preferable to the wet cooling system with respect to environmental impacts.

With regard to overall plant reliability, the Siting Council notes that, while we have found that the proposed use of the wet cooling system with the necessary contingency plan would have an acceptable impact on plant reliability (see Section III.F, above), we recognize that the potential exists for some level of reliability impacts as a result of the use of the wet cooling system. The Siting Council also notes, however, that the use of the dry cooling system would require use of "super low noise" fans in order to achieve acceptable noise impacts. The lack of operating experience with these fans raises concerns related to operational reliability. Consequently, as a result of our finding regarding the reliability impacts of the wet cooling system, and the lack of conclusive evidence regarding the potential reliability impacts of use of the "super low noise" fans, the Siting Council finds that the dry cooling system and the wet cooling system are comparable with respect to facility reliability.

With respect to cost, the Siting Council notes that the cost analyses presented by EPEC in the FEIR are more comprehensive and better documented than those presented earlier in this proceeding. In addition, the basic cost estimating methodology employed is appropriate. However, some of the underlying assumptions appear to be questionable. For example, the use of a five percent of TDC value for calculating maintenance costs for both the wet and dry cooling systems is unsubstantiated and is in direct conflict with information contained in an Electric Power Research Institute report "Survey of Water-Conserving Heat Rejection Systems" ("EPRI Report"), which states in part that maintenance requirements for dry cooling tower systems "generally should be less than for comparable wet cooling tower systems" (p. 2-37).[205] Due to the significantly higher TDC for the dry cooling system, the assumption of the same relative percentage for maintenance costs between the two systems could lead to a significant overstatement of maintenance costs for the dry cooling system relative to the wet cooling system.[206] Further, EPEC's annual overall O&M costs for the dry cooling system are calculated to

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205/ The Siting Council took administrative notice of the EPRI Report during the course of hearings in this proceeding (Tr. 6, pp. 67-68).

206/ At five percent of TDC, EPEC calculated maintenance costs to be approximately $159,000 for the wet cooling system and approximately $368,000 for the dry cooling system (Exh. EPEC-19, Table 5.9.3-3).

be approximately $1.9 million more than those of the wet cooling system. Adjusting this annual amount to reflect the impact of the $1.1 million cost assumed for capacity penalties with the dry cooling system still leaves approximately $786,000 in additional O&M costs for the dry cooling system relative to the wet cooling system. In light of EPEC's earlier assertions that use of the dry cooling system (without considering capacity penalties) would result in an annual savings of $300,000, such a significant difference appears to be highly questionable.

In regard to the $1.1 million annual economic penalty assigned to the dry cooling system to reflect capacity rating penalties associated with the dry cooling system, the Siting Council recognizes that such costs may be legitimate for consideration in a comparison of technologies. The Siting Council notes, however, that EPEC has chosen to operate its proposed facility at 146 MW rather than the full design capacity of 161 MW. Thus, while use of the dry cooling system would result in less efficient use of fuel, it is not clear that EPEC necessarily would need to incur the full capacity penalties identified if additional fuel were available (Exh. HO-RR-74). Nevertheless, the Siting Council recognizes that additional fuel use would lead to higher fuel costs, which could be of a similar order of magnitude.

The Siting Council also notes that EPEC did not include any economic penalty costs which may occur with the wet cooling system as a result of potential reductions in plant availability due to implementation of the contingency plan. Rather, EPEC's cost analysis assumes that potable water would be available to supply the full cooling water needs during the six percent of the year when the contingency plan will need to be implemented. While the Siting Council has found that the likelihood that plant availability will be affected by implementation of the proposed contingency plan is small, and recognizes that such "worst case" availability impacts would not occur on an annual basis, some recognition of the potential cost implications of such reduced availability would have been appropriate. Further, while EPEC's assumption that full cooling water requirements would need to be supplied by potable water for six percent of the year throughout the plant's life is clearly conservative from a cost perspective, such a cost "penalty" associated with mitigation is very likely considerably less than the costs which would be incurred in a given year as a result of reduced plant availability.

These concerns indicate that the total annual O&M costs of the dry cooling system (accounting for approximately two thirds of the $2.9 million annualized difference) may well have been significantly overstated relative to the O&M costs of the wet cooling system, perhaps by as much as 50 percent. Therefore, EPEC has failed to demonstrate that use of the dry cooling system would not be economically viable for the proposed project. Nevertheless, even if the entire $1.9 million difference in annual O&M costs (including capacity penalty costs) is disregarded, the record still identifies an annual cost difference of approximately $1.0 million based on total capital costs of the dry cooling system relative to the wet cooling system. Further, the Siting Council notes that the capital cost information which forms the basis of EPEC's analysis is largely supported by vendor information. In addition, the EPRI report further supports the overall cost benefits of wet cooling systems relative to dry cooling systems (EPRI Report, pp. S-2, 2-76). Therefore, the Siting Council finds that the wet cooling system proposed for use by EPEC is preferable to the dry cooling system on the basis of cost.

The Siting Council has found that the dry cooling system is preferable to the wet cooling system with respect to environmental impacts. The Siting Council also has found that the wet cooling system and the dry cooling system are comparable with respect to reliability. Finally, the Siting Council has found that the wet cooling system is preferable to the dry cooling system with respect to cost.

In making a determination as to whether the wet cooling system or the dry cooling system better achieves the balance between cost, environmental impacts and reliability, it is appropriate to consider the degree of benefits associated with each. In regard to the environmental benefits associated with use of the dry cooling system, the Siting Council notes use of the dry cooling system would result in no alteration of the current flow patterns of the upper Charles River. By contrast, use of the wet cooling system would result in a six percent annual increase in the frequency of low flow events in the upper Charles River relative to current conditions. The Siting Council notes, however, that EPEC has established that this increase in the frequency of low flow events would not have a negative impact on the upper Charles River upon compliance by EPEC with the ORDER set forth in Section III.E.3.c.vii, above. In regard to the cost benefits associated with use of the wet cooling system, despite the problems with EPEC's cost analysis described above, EPEC has established that significant annual cost savings of at least $1.0 million would be achieved through the use of the wet cooling system.

The Siting Council notes the difficulties inherent in balancing competing cost and environmental consideration. In this instance, EPEC had identified a stringent environmental mitigation plan (ceasing its effluent diversion when such diversion would cause streamflow in the upper Charles River to fall below three cfs) which, upon compliance with the ORDER set forth in Section III.E.3.c.vii, above, ensures that the effluent diversion would have an acceptable impact on waterways. EPEC further has established a significant annual cost difference between the wet cooling and dry cooling technologies. A potential environmental impact which has been adequately minimized cannot justify the significant additional cost associated with the dry cooling technology in this case.

Accordingly, the Siting Council finds that EPEC's use of the proposed wet cooling system with the contingency plan is preferable to the use of any of the cooling system alternatives with respect to achieving the appropriate balance among cost, environmental impacts, and reliability.

I. Conclusions on the Proposed and Alternative Facilities

The Siting Council has found that the primary site for the proposed facility is superior to the alternative site in terms of cost, environmental impacts, and reliability. The Siting Council also has that EPEC's use of the proposed wet cooling system with the contingency plan is preferable to the use of any of the cooling system alternatives with respect to achieving the appropriate balance among cost, environmental impacts, and reliability.

Accordingly, the Siting Council finds that the construction and operation of the proposed facilities at the primary site is acceptable in terms of cost, environmental impacts, and reliability.

IV. DECISION AND ORDER

The Siting Council finds that the construction and operation of the proposed generating facility and ancillary facilities are consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Further, EPEC must comply with the seven ORDERS[207] set forth in Section III.E.13. In addition, we note that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal with the Siting Council. Therefore, the Siting Council further ORDERS EPEC to notify the Siting Council of any changes other than minor variations to the proposal so that the Siting Council may decide whether to inquire further into that issue.[208]

Accordingly, the Siting Council hereby APPROVES the petition of EPEC to construct a bulk generating facility and ancillary facilities.[209] Because issues addressed in this decision relative to this facility are subject to change over

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207/ We note that the Siting Council must find that EPEC has complied with all conditions before EPEC can commence construction of the facility. The ORDERS must be fulfilled by EPEC in the course of construction and operation of the facility.

208/ The petitioner is obligated to provide the Siting Council with sufficient information on changes to enable the Siting Council to make this determination.

209/ During the course of this proceeding, EPC sold half of its interest in the proposed project to two subsidiaries of Jones Capital, Jones Charles River and Jones Medway, and EPC and Jones Capital formed MPLP to develop the project. Based upon our review of the testimony and documents in the record regarding MPLP, the Siting Council hereby determines that the findings in this decision apply to MPLP.

time, construction of the proposed generating facility and ancillary facilities must be commenced within two years of the date of this APPROVAL.

Michael D. Ernst
Hearing Officer

Dated this 29th day of August, 1991.

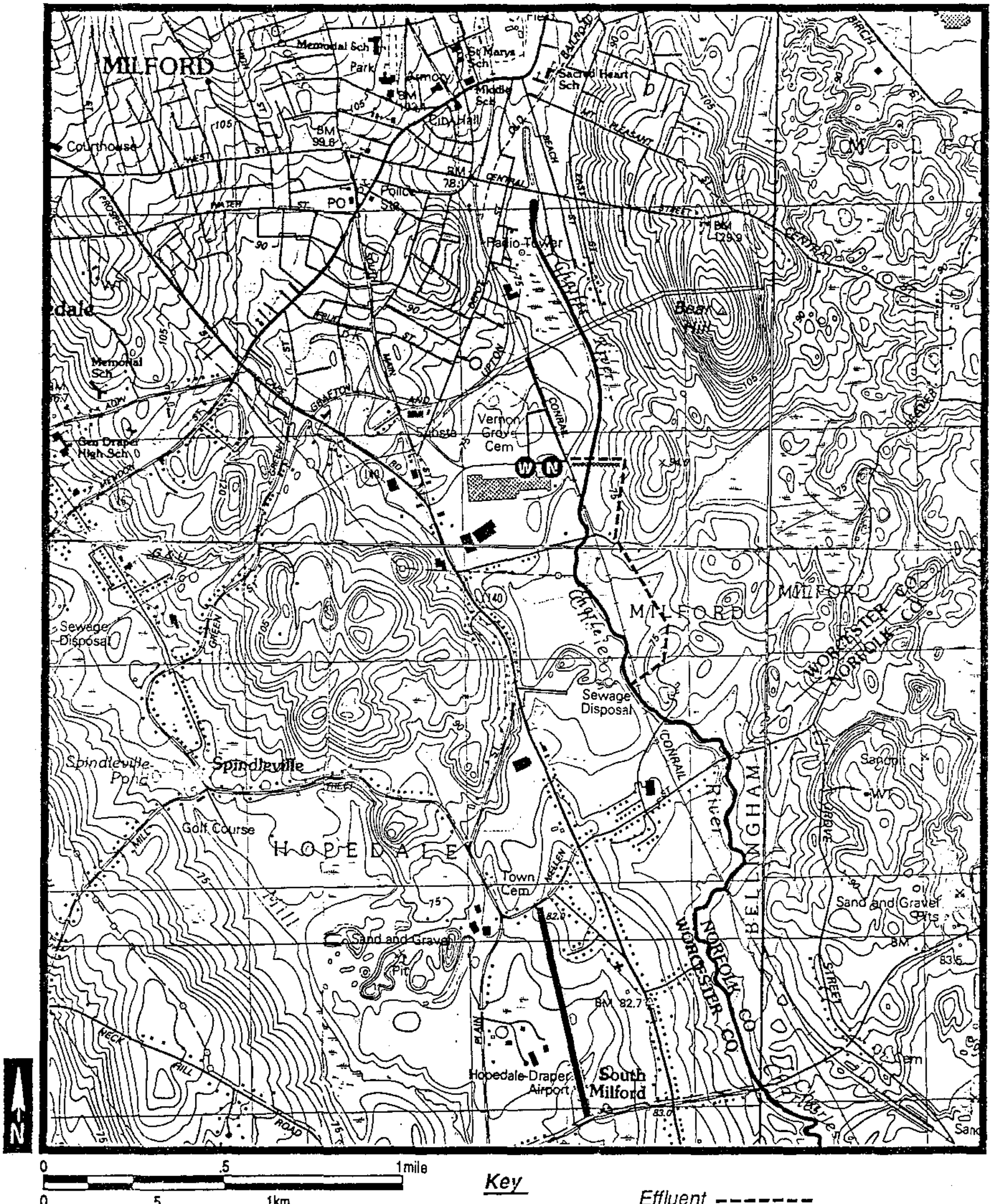
UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 29, 1991 by the members and designees present and eligible to vote. Voting for approval of the Tentative Decision as amended: Gloria Cordes Larson (Secretary of Consumer Affairs and Business Regulation); Thomas McShane (for Susan F. Tierney, Secretary of Environmental Affairs), Joseph Donovan (for Daniel S. Gregory, Secretary of Economic Affairs), Paul W. Gromer (Commissioner of Energy Resources), Mindy Lubber (Public Environmental Member), Michael Ruane (Public Electric Member), Kenneth Astill (Public Engineering Member), and Joseph C. Faherty (Public Labor Member).

Gloria C. Larson

Gloria Cordes Larson
Chairperson

Dated this 29th day of August 1991

Figure # 1



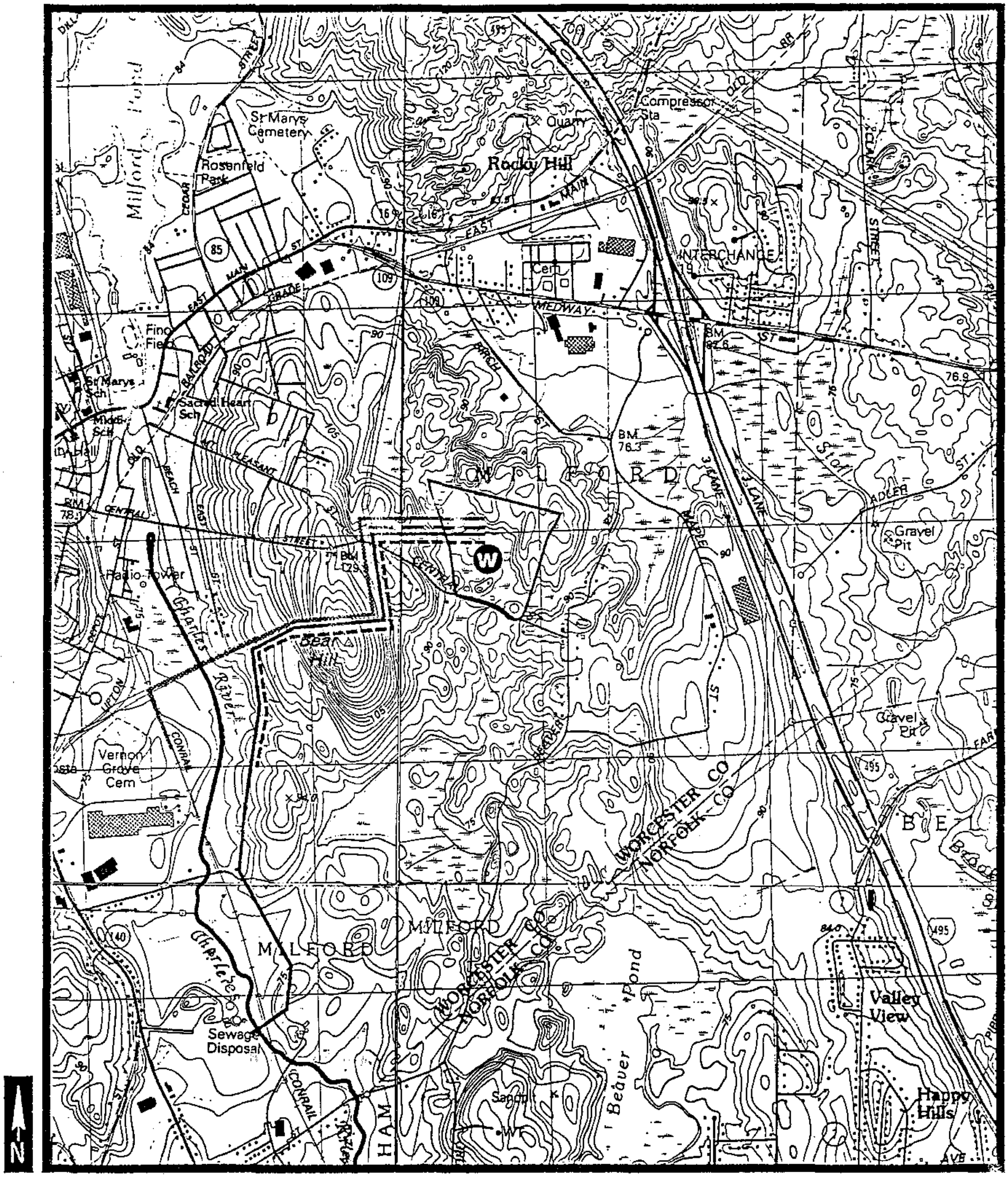
Key

Effluent
Sewer
Electric
Water Main
Natural Gas Interconnect

Source: U.S.G.S. 7.5 X 15 Minute Series (Topographic Quads) of Milford, MA 1982 - Medfield, MA 1987 - Uxbridge, MA 1982 - Franklin, MA 1987

Utility Routes Associated with the Proposed National Street Site

Figure # 2



0 .5 1 mile

0 .5 1km

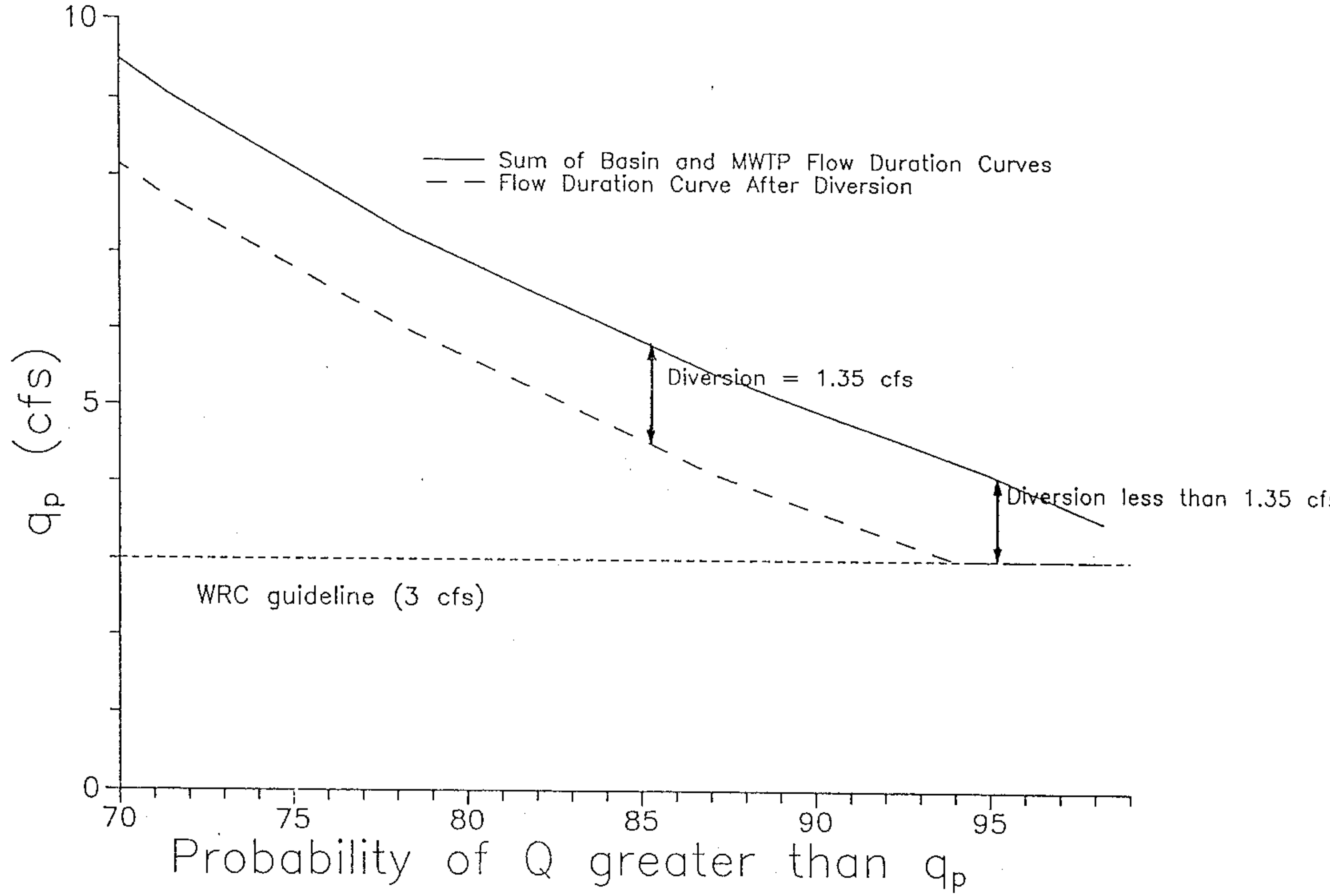
Source: U.S.G.S. 7.5 X 15 Minute Series (Topographic Quads) of Milford, MA 1982 - Medfield, MA 1987 - Uxbridge, MA 1982 - Franklin, MA 1987

Key

Effluent
Electric
Natural Gas
Sewer
Water Main W

Utility Routes Associated with the Alternate Site

Figure # 3



Flow Duration Curve for Box Pond Including Proposed Diversion

TABLE 1

DEMAND FORECASTS
(NEPOOL Adjusted Summer Peak in MW)

Year	1989 CELT Forecast	1990 CELT Forecast	EPEC Alternative Forecast	1990 Low C&LM Forecast	1990 High C&LM Forecast	1991 CELT Forecast	1991 High C&LM Forecast	1991 Low C&LM Forecast
1989	20,000[1]	20,000[1]	20,000[1]	20,125	19,875	N/A	N/A	N/A
1990	20,300	19,989	20,640	20,168	19,810	20,100	19,930	20,270
1991	20,740	20,087	21,300	20,321	19,853	19,875	19,655	20,096
1992	21,180	20,674	21,982	20,971	20,378	19,630	19,352	19,909
1993	21,641	21,335	22,686	21,690	20,980	19,694	19,361	20,028
1994	22,147	22,039	23,411	22,451	21,627	19,710	19,316	20,104
1995	22,689	22,540	24,161	22,996	22,084	19,773	19,326	20,220
1996	23,203	22,970	24,934	23,481	22,460	20,028	19,526	20,530
1997	23,668	23,328	25,732	23,889	22,767	20,359	19,809	20,909
1998	24,115	23,732	26,555	24,338	23,126	20,707	20,108	21,307
1999	24,686	24,287	27,405	24,928	23,646	21,183	20,534	21,832
2000	25,340	24,912	28,282	25,590	24,234	21,628	20,932	22,324
2001	25,766	25,351	29,187	26,058	24,644	22,014	21,274	22,755
2002	26,205	25,754	30,121	26,489	25,020	22,506	21,730	23,282
2003	26,668	26,248	31,085	27,012	25,484	23,038	22,232	23,845
2004	27,261	26,806	32,079	27,602	28,237	23,377	22,528	24,207
2005	N/A	27,417	33,106	N/A	N/A	24,079	23,224	24,934

Sources: Exhs. EPEC-1, II-21, II-22, HO-N-2, HO-RR-23, HO-RR-106.

<u>Note</u>:

1. Actual 1990 Peak Load.

TABLE 2

FIRST YEAR OF CONTINUOUS NEED FOR
AT LEAST 146 MW OF CAPACITY WITHIN NEPOOL
-CELT AND ALTERNATIVE FORECASTS-

	Supply Scenarios						
Demand Forecast	1	2	3	4	5	6	7
1989 CELT Forecast	1994	1994	1994	1994	1994	1994	1994
1990 CELT Forecast	1994	1995	1994	1994	1994	1994	1994
1990 Low C&LM Forecast	1994	1994	1994	1993	1994	1994	1994
1990 High C&LM Forecast	1994	1995	1995	1994	1995	1995	1994
1991 CELT Forecast	2001	2001	2000	2000	2001	2001	2000
1991 Low C&LM Forecast	2000	2000	1999	1999	2000	2000	1999
1991 High C&LM Forecast	2001	2001	2001	2001	2001	2001	2001
EPEC Alternative Forecast	1992	1992	1992	1992	1992	1992	1992

Sources: Exhs. EPEC-1, pp. II-19 to II-21, HO-N-25, Table 2, HO-RR-24, HO-RR-106.

TABLE 3

NUMBER OF CASES SHOWING NEED FOR
AT LEAST 146 MW OF CAPACITY
-CELT AND ALTERNATIVE FORECASTS-

Demand Forecast	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1989 CELT Forecast	0	0	7	0	0	0	0	0	0	0
1990 CELT Forecast	0	0	6	1	0	0	0	0	0	0
1990 Low C&LM Forecast	0	1	6	0	0	0	0	0	0	0
1990 High C&LM Forecast	0	0	3	4	0	0	0	0	0	0
1991 CELT Forecast	0	0	0	0	0	0	0	0	3	4
1991 Low C&LM Forecast	0	0	0	0	0	0	0	3	4	0
1991 High C&LM Forecast	0	0	0	0	0	0	0	0	0	7
EPEC Alternative Forecast	7	0	0	0	0	0	0	0	0	0
Total	7	1	22	5	0	0	0	3	7	11

Sources: Exhs. EPEC-1, pp. II-19 to II-21, HO-N-25, Table 2, HO-RR-24, HO-RR-106.

TABLE 4

FIRST YEAR OF CONTINUOUS NEED FOR
AT LEAST 146 MW OF CAPACITY WITHIN NEPOOL
-LOAD GROWTH SENSITIVITY ANALYSIS-

	Supply Scenarios						
Demand Forecast	1	2	3	4	5	6	7
0.5% Constant Growth	2001	2003	2001	2001	2001	2001	2001
1.0% Constant Growth	1999	2001	1999	1999	2000	2000	1999
1.5% Constant Growth	1995	1998	1995	1994	1995	1995	1995
2.0% Constant Growth	1994	1995	1994	1994	1994	1994	1994
2.5% Constant Growth	1993	1994	1993	1993	1993	1994	1993
3.0% Constant Growth	1992	1993	1992	1992	1993	1993	1992
3.5% Constant Growth	1992	1992	1992	1992	1992	1992	1992
4.0% Constant Growth	1992	1992	1992	1992	1992	1992	1992
4.5% Constant Growth	1990	1992	1990	1990	1992	1992	1990
5.0% Constant Growth	1990	1990	1990	1990	1990	1992	1990

Sources: Exhs. EPEC-1, pp. II-19 to II-21, HO-N-25, Table 2, HO-RR-24, HO-RR-106.

TABLE 5

TOTAL NET COST SAVINGS TO REGION[1]
(1993-2012)
($Million in 1993 Dollars)

Load Growth Scenario	Capacity Expansion Scenarios: Combustion Turbine	Combined Cycle	AFB Coal
1990 CELT Forecast	97.1	88.4	128.8
1991 CELT Forecast	9.1	10.9	61.6
0.85 Percent Constant Load Growth	3.0	27.0	74.6
1.0 Percent Constant Load Growth	15.7	37.9	85.8
1.5 Percent Constant Load Growth	54.5	62.2	107.2
2.0 Percent Constant Load Growth	83.3	74.5	116.6

Sources: Exhs. HO-RR-22, HO-RR-36, HO-RR-85, HO-RR-106.

Note:

1. These cost savings would accrue to the region as the result of the displacement of more expensive units by the proposed EPEC project.

TABLE 6

FIRST YEAR OF NET COST
SAVINGS TO REGION[1]

Load Growth Scenario	Capacity Expansion Scenarios		
	Combustion Turbine	Combined Cycle	AFB Coal
1990 CELT Forecast	1998	1994	1994
1991 CELT Forecast	2001	2001	2001
0.85 Percent Constant Load Growth	2000	1999	1999
1.0 Percent Constant Load Growth	2000	1998	1998
1.5 Percent Constant Load Growth	1999	1996	1996
2.0 Percent Constant Load Growth	1998	1995	1995

Sources: Exhs. HO-RR-22, HO-RR-36, HO-RR-85, HO-RR-106.

Note:

1. These cost savings would accrue to the region as the result of the displacement of more expensive units by the proposed EPEC project.

TABLE 7

ESTIMATED NET REGIONAL AND MASSACHUSETTS
AIR QUALITY IMPACTS FROM DISPLACEMENT[1]
(Tons per Year)

Type of Emission	EPEC Emissions	NEPOOL Net Emission Reductions from Displacement		MA Net Emission Reductions from Displacement[2]	
		1993	2002	1993	2002
Sulfur Dioxide	0.0	3244.1	2127.5	2050.7	1057.8
Nitrogen Oxides	64.0	864.8	639.9	465.8	254.1
Particulates	6.4	87.8	54.5	45.3	19.0
Volatile Organic Compounds	17.6	(0.2)	2.0	(6.3)	(9.8)
Carbon Monoxide	83.9	10.0	13.2	(18.5)	(45.7)
Methane	41.7	633.8	493.2	344.0	194.9
Carbon Dioxide	237,410	173,791	120,922	(5228)	(131,566)

Source: Exh. HO-RR-38

Notes:

1. Assumes that all required new units are generic gas-fired combined cycle units. Use of combustion turbines or AFB coal plants as generic new units would generally increase the emissions displaced by the proposed EPEC project.

2. Assumes that no generic new units are located in Massachusetts. As a result, no Massachusetts emission savings are credited to the displacement of such units.

TOWN OF MILFORD, MASSACHUSETTS
ZONING BOARD OF APPEALS
TOWN HALL
52 MAIN STREET
MILFORD, MASSACHUSETTS 01757

(508) 634-2302

DECISION

This is the petition of Enron Power Corporation and Milford Power Limited Partnership, 70 Walnut Street, Wellesley, MA for a Special Permit pursuant to Section 2.3 of the Zoning By-Law. Said Special Permit is sought to allow the establishment of an industrial gas fueled power plant on a parcel of land located on the northerly side of the terminus of National Street, which parcel is currently owned by Howard A. Fafard.

Upon receipt of the above petition, a public hearing was scheduled thereon for Thursday, March 28, 1991 in the Meeting Room of the Upper Town Hall, 52 Main Street, Milford, MA at 7:20 P.M. Notice of the time, place and subject matter of the petition was given, as required by law.

The matter came on for hearing at the time and place thereof. Present were Chairman Andrej Thomas Starkis, members William J. Balmelli, Fernando Rodrigues, Jonathan M. Bruce and Edward H.P. Barnhill and alternate members John Speroni, Jr. and Anthony Consigli. The alternate members participated in the public hearing but not in the deliberations or vote. The petitioners were represented by Attorney John Fernandes, Jude Rolfes, Vice-President of Enron Power Corporation (EPC) and numerous other employees and consultants who presented evidence in favor of the petition. Also present were numerous residents of the area of Town at issue, organized by Lena McCarthy and Margaret Knowlton, who presented evidence against the petition. Also represented were representatives of interested environmental organizations and officials of the Town of Milford, including the Board of Selectmen and their consultant, Dr. Alfred Scaramelli. During the course of the hearing, it being apparent that several nights of hearing would be necessary, the petitioner and and the Board agreed in writing to extend the time for hearing and decision first to May 15, 1991 and later to June 1, 1991. The hearing continued until approximately midnight on March 28, 1991 whereupon it was continued by unanimous vote to 7:00 P.M. on April 2, 1991 at the same location. The hearing continued until approximately midnight again whereupon it was unanimously voted to continue it yet again until 7:00 P.M. on April 9, 1991 at the same location and at that meeting, after some four hours of testimony, there was another unanimous vote to continue until 7:00 P.M. on April 30, 1991 at the same location. Once again, after some four hours of hearing evidence, the Board unanimously voted to continue the matter until 7:00 P.M. on May 2, 1991 at the same location. At this hearing, after another four hours of evidence, the Board unanimously voted to close the public hearing and took the matter under advisement. At this time, the Board began deliberations. At all of the foregoing continued meetings all of the regular members and the two alternate members listed above were present. After deliberation, the five regular members of the Board unanimously voted to grant the Special Permit subject to the numerous conditions set forth below. In so voting, the Board based its decision upon the following findings:

1. The petitioners propose to build an approximately 140 megawatt natural gas fueled independent power production facility on a 6.87 acre, more or less, parcel of land owned by Howard A. Fafard at the end of National Street in Milford. The site is zoned Highway Industrial (IB) and is located right next to a heavy industrial plant commonly known as Foster Forbes Glass. The Facility will have one single one hundred ten (110) MW Westinghouse gas turbine generator in combined cycle with the nominal 40 MW steam turbine generator. The project will be supplied natural gas on a firm year round basis by Distrigas, a Massachusetts Corporation, and year round transportation will be available from Commonwealth Gas Company and Algonquin Gas Transmission Company.

2. The site of the proposed Facility is presently utilized in part for a parking lot for 30-35 trailers. All of the primary buildings, storage tanks, and ancillary structures of the Facility will be situated on site.

   The site is easily accessible to all necessary utilities. An existing New England Power Company 115 kV overhead transmission line is situated approximately 1,000 feet to the north. There is a 12 inch water main located in National Street and an Algonquin Gas Transmission Company pipeline is located along railroad tracks which are adjacent to the site. The Milford Wastewater Treatment Plant (MWTP) is situated one-half mile to the south in the Town of Hopedale. Effluent from MWTP will serve as cooling water for the project and will be routed in a common right of way with a Milford Sewer Commission sewer line to be constructed in a northerly direction from the MWTP.

3. In determining whether or not to grant the Special Permit, this Board must be guided by the standards set forth within Section 1.10.1 of the By-Law. Subsections (a) and (b) are fairly clearly met. Town Meeting last year specifically amended the Zoning By-Law to allow the proposed use by Special Permit. No standards were set other than those within Section 1.10. The proposed use, therefore, is clearly in harmony with the general purpose and intent of the By-Law and the Special Permit,with the conditions imposed below clearly conforms to applicable general and specific provisions of the By-Law.

4. The standard within Section 1.10.1(c) is also clearly met. During operation, the number of employees and visitors is low relative to uses otherwise permitted as of right to locate on the site. The impacts on traffic will be negligible. Fuel will come to the site by pipeline. Operationally, the use will have less of a traffic impact than many uses allowed as of right. Traffic impacts may be greater during construction, but even then the impacts will be less than for other uses because substantial construction material delivery will be by rail.

5. As all agreed at the hearing, the key considerations are within Section 1.10.1(d) and they are the questions of whether or not the proposed Facility will cause substantial harm to the neighborhood or create a nuisance or hazard affecting the health, safety or general welfare of the citizens of the Town of Milford. For the reasons discussed below, and with the conditions attached to this grant, the Board concluded the standard within Section 1.10.1(d) is met.

6. The primary issues raised at the hearing were issues of air quality impacts, noise, wastewater use impacts, impacts upon water supply and nearby well fields, electric

and magnetic effect, and affect upon the Charles River and upon an underlying aquifer. The Board heard many hours of testimony on each of those concerns and took in evidence literally thousands of pages of documentary evidence on each side of these issues. In the final analysis, the Board relied most heavily upon the testimonial and documentary submissions of certain employees of ENSR Consulting and Engineering, retained by Enron. Those included Fred Sellars on air and sound impacts and methods and means of reducing same; Mark Gerath, Senior Hydrologist in relation to effects upon the water supply, the aquifer and the Charles River. Dr. Mary Best, Senior Biologist and Dr. Bruce Fishman, Bacteriologist on the use of effluent. Also relied upon were Dr. Peter Valberg of the Harvard School of Public Health on electromagnetic fields (EMF) and James Kemp, Vice-President of Plant Start-Up & Operations for Enron as to problems and solutions in start-up and operation of the plant. Finally, the Board relied upon the detailed environmental review and recommendations of Dr. Alfred Scaramelli of Bay State Power Associates, the environmental engineer retained by the Town. Also relied upon heavily, but not exclusively, was the Draft Environmental Impact Report dated January 1991, and the accompanying documentation.

7. In the final analysis, the Board concluded that although the issues set forth above and others raised are very real issues, the petitioner had done much to address those issues and minimize impacts upon the neighborhood and the Town. The Selectmen, through Dr. Scaramelli, suggested even more strenuous environmental standards and methods of testing compliance. (many of which are adopted below). Noise will be controlled by fencing with acoustical barriers and sound insulated enclosures around the gas turbine and location of facilities to minimize noise, among other protection, and will have to meet stringent noise level requirements. To minimize effects upon air quality only one stack is allowed and by-pass stacks are not permitted. Additionally the Facility

will have a continuous emission monitoring system utilizing Selective Catalytic Reduction as oxides of nitrogen control technology and significant reporting obligations. The wastewater utilized will come from Milford's state of the art tertiary treatment plant and will therefore be low in contaminants. Cooling tower drift rate will be minimal and controlled and there will be significant testing for any effects upon groundwater and the environment. The Godfrey Brook wellfield will be further protected by a testing program to evaluate groundwater flow and water quality in and around the site and the wellfield, among other protections. Concerns about electromagnetic fields are minimized considering the location of the site relatively far from existing or possible future residences. Diversion of part of the wastewater flow from the Sewer Treatment Plant from the Charles River to the proposed Facility will be controlled and measured so as to have no adverse impact upon the flow of the Charles River.

8. With the numerous and significant conditions below, and based upon the submission of the petitioner and the testimony of the many experts and other witnesses, it is the conclusion of the Board that the grant of the Special Permit, with those conditions, and the operation of the proposed power plant under those conditions, will not cause harm to the neighborhood and will not create any nuisance or hazard affecting the health, safety or general welfare of the citizens of the Town of Milford.

Having made the above findings, the Board voted unanimously as set forth above, to grant the Special Permit requested, subject to the following conditions and requirements, all of which are to be considered to be binding upon the petitioners and/or their respective successors and assigns:

1. The Company shall retain existing mature trees along the site perimeter and comply with the Company proposed Landscape Plan attached as Exhibit C to the "Report" dated January, 1991, on file herewith (hereafter referred to as "the Report"). The Company shall also, in accordance with the Variance granted concurrent herewith, construct a ten (10) foot high wooden fence (with acoustical control panels) along the cemetery property line and the property line running in a northerly direction up to the Penn Central Right of Way, which fence shall be on top of a three foot earth berm. (If said Variances does not stand, the wooden fence shall be six feet high). The balance of the property shall be enclosed by at least a six foot high chain link fence. If there is a driveway behind said wooden fence running to property owned by others, there shall be a separate six foot high chain link fence separating said driveway from the Facility. The proposed tree and shrub plantings along the cemetery boundary line shall be between the wooden fence and the cemetery. From time to time, the Company shall replace any dying or severely damaged trees or shrubs on the property.

2. Provide sound insulated enclosures around the gas turbine, the section between the gas turbine and heat recovery steam generator, steam turbine generator, and the natural gas pressure reducing and metering station (either on site or off site).

3. Minimize nighttime lighting to that necessary for safe operation of the Facility. Maximize the use of spot light and minimize area lighting. Use of sodium lamps shall not be allowed.

4. At the point in time when the Facility is deemed to have operated for its useful life and the Company has determined it is no longer prudent to staff and maintain the Facility, the Company shall cause the Facility to be demolished and the land returned to a clean, graded and seeded condition.

   Prior to issuance of a Building Permit to the Company, the Company and the Town shall enter into a Demolition Fund Escrow Agreement whereby both parties agree that within 15 days after the date of issuance of the Building Permit, and on the same day each year thereafter for a period of 20 years, the Company shall deposit $15,000 into an interest bearing escrow account in a Massachusetts bank.

If the Company promptly complies with the above Facility demolition obligation at the end of the Facility's useful life, the balance in the escrow account, including all accrued interest, shall be released to the Company upon successful demolition and land restoration as determined by the Board of Selectmen. In the event the Company does not commence compliance with the above-described demolition and restoration within sixty (60) days after receipt of written notice from the Board of Selectmen to commence, all monies in the escrow account, including accrued interest, shall be released to the account of the Town to be utilized by the Town for demolition and restoration. Any balance remaining after such demolition and restoration by the Town shall be retained by the Town for its general purposes.

5. The Company shall maintain the Facility site and any utility easement routes in a clean and orderly condition, and shall routinely perform landscape care and Facility painting, and shall keep the site generally free of litter.

6. Once in commercial operation, construction related facilities and equipment shall be removed from the site as quickly as practically possible.

7. Stack lighting or marking requirements shall be no more than that required by the FAA.

8. Location of the steam turbine, gas turbine, HRSG, cooling towers and switching yard on the site shall be substantially similar to those locations shown on Exhibit B, to the Report, except as may be modified as a result of Town Engineer approval. Location of all equipment and structures must comply with Town approved operational and safety procedures as described herein.

9. The Company shall design and construct the cooling towers such that air cooled heat exchange coils (steam or hot water) will be added to the cooling tower as plume abatement equipment within a reasonable time after written notice from the Board of Selectmen (received within the first two years of commercial operation) that they have determined that the cooling tower plume causes a significant aesthetic impact in at least one area of Town.

10. During construction of the Facility, National Street shall be swept or washed two times per week to control mud and dust, and more frequently if so directed by the Highway Surveyor.

11. The Company shall provide up to $15,000 in off-site landscape planting and services within Precinct Three of the Town with such off-site landscaping scope of work to be determined by the Planning Board prior to commercial operation of the Facility.

12. Natural gas shall be the only gas turbine fuel burned or stored on the site.

13. The Facility shall contain only one flue gas exhaust stack which shall be connected to the exit of the heat recovery steam generator. There shall be no by-pass stacks. The Company shall use all reasonable efforts to obtain a waiver from the Massachusetts Department of Environmental Protection Division of Air Quality (DEP) to allow a stack height of approximately 104 feet. However, if a waiver cannot be obtained, the height of the chimney or flue gas exchaust stack for the emissions of combustion products at the site shall not exceed the minimum acceptable stack height required for the project by DEP, such height not to exceed 165 feet.

14. The cooling tower shall have a maximum drift rate of 0.005 percent of the water recirculation rate. The Company shall submit cooling tower specifications to the Town Engineer that state, at a minimum, drift rate percentage, drift particle size distribution, and drift rate prior to construction of the cooling tower, and shall certify to the Town Engineer that the drift eliminator installed by the Company complies with these specifications. The Company shall submit to a test and measurement of the drift rate from time to time if in the Town Engineer's opinion there is reasonable cause to believe that drift rate is exceeding guaranteed values or causing an adverse impact.

15. Prior to issuance of a Building Permit, the Company, in cooperation and agreement with the Milford Water Company, shall prepare and submit a plan for review, modification and approval, which approval shall not be unreasonably withheld, to the Health Agent that specifies a testing program and procedure to evaluate groundwater flow, soil and water quality in and

around Godfrey Brook wellfield prior to construction and during operation of the Facility. The test program shall address limits of Zone 2, location and type of sampling stations on the Company's property and off-site if available, frequency of sampling, sampling procedures, components to be tested, test methods and reporting results. Submittal of this plan shall be within 60 days of issuance of this Special Permit.

16. No obnoxious or offensive odors from the Facility shall be reasonably detectable beyond the Facility property line. Any odor related complaints shall be promptly investigated by the Company. The nature of the complaint, status of the investigations, and resolution shall be reported in writing to the Health Agent within seven days of a complaint, and corrective action taken as appropriate.

17. The Company shall install and operate Selective Catalytic Reduction as oxides of nitrogen control technology.

18. The Company shall make a one time contribution of $5,000 prior to the start of commercial operations of the Facility to the Massachusetts Re-Leaf program which is a tree seedling planting program for reduction in carbon dioxide.

19. The Facility shall be equipped with a continuous emission monitoring (CEM) system in accordance with Massachusetts DEP requirements.

20. The Company shall submit quarterly reports to the Board of Selectmen once the Facility is operational on the air emissions from the Facility and the meteorology at the site. Such reports shall include all data and information filed with the Massachusetts DEP during the quarter and any additional data as may be appropriate based upon operating circumstance. A comprehensive summary of plant operation and emissions performance during the quarter including CEM results shall also be provided.

21. The Company shall maintain a properly located and calibrated meteorological data collection and recording station, recording at least wind speed, wind direction and temperature. Meteorological

data and Facility operating logs shall be made available to the Health Agent for use in investigating any complaints related to the Facility.

22. The Company shall actively pursue participation in utility sponsored energy conservation programs, e.g. demand side management, and shall annually for a five year period provide the Board of Selectmen with a written report on the Company's efforts in this area.

23. The Company shall install and maintain the noise control equipment and treatments as set forth below by the Company during startup and operation of the Facility. Noise abatement features as proposed by the Company shall include at least the following:

> A building surrounding the gas turbine and steam turbine of sound absorbing perforated sandwich-panel type construction.
>
> Gas turbine air inlet will be lined with sound abatement material and equipped with deflector baffles over the inlet filters and modified wet filter media.
>
> Piping sized for reduced velocity and insulated where required.
>
> Silencers and mufflers on all main emergency and bypass vents.
>
> High efficiency motors and transformers.
>
> In addition, the Plant layout shall be sized to optimize shielding. For example, the cooling tower is proposed to be located in the rear of the plant and the water tanks are on the outside to shield noise. A low noise cooling tower has been selected with additional sound abatement.
>
> Internal acoustical treatment for the HRSG stack.

24. During startup or at any other applicable times, the Company shall provide at least 48 hours notice to the

Town Engineer, Health Agent, local radio and newspapers, of any planned major steam venting. All major steam vents shall be equipped with silencers, and the Company shall undertake any other measures for silencing as may be required by the Town Engineer.

25. The Facility shall be designed and constructed with a condenser system to condense steam in the event of a steam turbine trip or outage. Steam venting to the atmosphere shall only be permitted during emergency conditions and initial boiler boilout and steam pipe cleaning during construction start-up.

26. During commercial operation of the Facility, Facility related noise shall not result in a measured increase in L90 ambient noise level of more than 4 dBA at any time, day or night, at Receptors No. 2,3 and 4, as shown on Exhibit A. Prior to issuance of a Building Permit for the Facility, the Company shall submit a plan for review, modification and approval, which approval shall not be unreasonably withheld, to the Town Engineer which specifies the testing protocol, measurement equipment, frequency and conditions for testing the Facility during the period of commercial operations to demonstrate compliance with the 4 dBA noise increase requirement. Ambient noise levels shall be established prior to issuance of a Building Permit. In addition, operation of the Facility shall not exceed tonal noise requirements as defined by the Massachusetts DEP. Submittal of this plan shall be within 60 days of issuance of this Special Permit.

27. The Company shall use all reasonable efforts to minimize noise during construction, startup and acceptance testing. The Town Engineer and Director of Health shall be notified at least 48 hours prior to any blasting.

28. Construction activity, including startup of equipment, shall be limited to the hours of 6:30 A.M. to 6:00 P.M. Monday through Saturday, excluding Federal holidays, except that light construction activities, not involving use of heavy equipment shall not be so restricted.

29. Rail or truck deliveries to the Facility site shall be limited to the hours of 7:00 A.M. to 6:00 P.M. Monday through Saturday, excluding Federal holidays.

The Company shall use all reasonable efforts to control truck delivery routes to the Facility such that all non-local area originating truck deliveries using Route 495 shall, if travelling south on Route 495, exit at the Route 85 exit and proceed to Route 16; all trucks travelling north on Route 495 shall exit at Route 109 and proceed to Route 16. Thereafter, all trucks shall follow Route 16 to Beach Street to Central Street, Depot Street, and then to National Street. The Town Engineer shall have the right to alter truck delivery routes from time to time. The Company shall also provide a safety guard (individual) at each non-gate activated railroad crossing in Milford to assist in vehicle and pedestrian traffic protection whenever the Company is receiving deliveries to the Facility by rail.

30. Prior to the issuance of a Building Permit for the Facility, the Company shall submit a plan containing testing procedures and the maximum concentrations of various compounds in the cooling water that will be considered acceptable for use in the cooling tower to the Town Engineer and Health Agent for review, modification and approval, which approval shall not be unreasonably withheld. Submittal of this plan shall be within 45 days of issuance of this Special Permit.

31. The Company shall maintain adequate disinfection treatment levels in the cooling water pipeline from the WWTP to the Facility as well as in the cooling tower basin. If chlorine is used as the disinfectant, it shall be purchased in the liquified form as a hypochlorite. The Company shall regularly test cooling tower water for the presence of fecal coliform and other constituents as described above, and make these test results available to the Health Agent, and to the Sewer Commissioners upon their request. A testing schedule will be as agreed upon with the Health Agent and the Town Engineer.

32. In the event of a total cooling tower shutdown exceeding four hours in length, the cooling tower basin shall be drained of cooling water with all drained wastewater discharged to the sewer, and

the cooling water in the pipeline shall be purged with potable water.

33. The Company shall use stainless steel tubing and piping in the condenser and cooling tower in lieu of copper tubing and piping, and such stainless steel tubing shall have minimal chromium content as consistent with good engineering practice.

34. The Company shall construct a potable water storage tank on the site with a capacity not to exceed 1,000,000 gallons which shall be designed to provide an alternative make-up water source to the cooling tower and boiler feedwater system. Only potable shall be stored in this tank. Said maximum gallonage may be stored in two (2) tanks if deemed appropriate by the Company.

35. Prior to issuance of a Building Permit, the Company shall submit a Stormwater Control and Discharge Plan to the Town Engineer, which plan shall protect the water supply sources of the Milford Water Company during construction and operation of the Facility, and such plan shall have prior approval from the Milford Water Company, and shall also provide for on-site groundwater monitoring wells at selected locations along the Company's property line to monitor stormwater detention basin leaks and chemical spills. Such plan shall be submitted within 90 days of issuance of this Special Permit.

36. The Company shall install and continuously record Charles River flow at a point within 200 feet below the discharge point of the Milford Wastewater Treatment Plant. The Company shall be allowed to use Milford wastewater effluent to the extent that measured river flow is equal to or greater than 3 cubic feet per second or such river low flow limit as established by appropriate Massachusetts regulatory agencies specifically for the Company's Facility, whichever river flow is greater. The Company shall reduce wastewater use, if necessary, to achieve the above minimum river flow requirements. The aforesaid point of flow measurement may be at a point greater than 200 feet below said discharge point if agreed to by the Town Engineer.

37. The Company shall continuously record wastewater usage and make available to the Sewer Commissioners wastewater usage and river flow data upon request.

38. The Company shall comply with all applicable industrial wastewater pre-treatment requirements prior to discharge to the Town sewer. All Facility wastewater, except sanitary waste, shall be piped to a wastewater treatment and holding tank prior to sewer discharge. The Company shall monitor Facility wastewater effluent flow and quality to the wastewater treatment and holding tank and shall test for such constituents and parameters as required by the Sewer Commissioner from time to time. In the event the wastewater does not meet pre-treatment requirements, it shall not be discharged to the sewer.

39. Prior to issuance of a Building Permit, the Company shall submit a comprehensive Spill Prevention, Containment and Control Plan for the Facility to the Town Fire Chief. Such plan shall be approved by the Milford Water Company and, at a minimum, shall contain a list of all chemicals to be used and stored at the Facility, including estimated quantities, a requirement to notify the Water Company and Fire Chief of any change in chemicals, design measures to prevent chemical spills, procedures to respond to a spill or Facility emergency, location and type of on-site fire fighting or spill control equipment, and any special techniques or requirements for dealing with fires or spills associated with individual chemicals. Such plan shall deal with both Facility construction and operation and shall be submitted within 120 days of issuance of this Special Permit.

40. Prior to issuance of a Building Permit, the Company shall submit an Emergency Response Plan to the Fire Chief. Such plan shall be submitted within 120 days of issuance of this Special Permit. The plan shall be updated by the Company on a yearly basis and more frequently as required by the Fire Chief.

41. Prior to issuance of a Building Permit, the Company shall submit a Facility construction and operation plan to the Milford Water Company and the Town

Engineer for review, modification and approval, which approval shall not be unreasonably withheld, describing general construction and operating procedures, erosion and sedimentation control techniques, fuel use and handling, handling of cleaning and degreasing chemicals, and subsurface construction techniques.

42. The Company shall employ automatic gas detection circuitry to locate in order to immediately respond to any gas leak involving the fuel gas building and gas turbine area.

43. If the Company uses hydrogen gases to cool the electrical generator driven by the gas turbine and/or steam turbine, the hydrogen gas shall be stored in permanently mounted horizontal cylinders with bollard protection. No more than 370 cubic feet of cylinder volume shall be installed at the site. The use, storage and unloading of hydrogen gas shall be in compliance with all applicable state and local fire safety requirements.

44. No underground storage of chemicals or liquids shall be allowed on the Facility site.

45. Except as provided below, the Company shall surround all outside chemical storage tanks with concrete dikes capable of holding at least 110 percent of the tank capacity with floor drains, if any, not to be connected to the Facility's wastewater discharge system. Ammonia and chlorine used at the Facility shall be delivered, stored and used in aqueous form. All chemical storage areas inside buildings, tanks for storage of cooling tower and boiler water conditioning chemicals and truck unloading areas shall be provided with curbing and drains, and such drains shall connect to a wastewater holding and treatment tank prior to sewer discharge.

46. None of the Special Permit conditions are in lieu of any approvals, permits or licenses that the Company must obtain for construction and operation of the Facility.

47. In the event that any one or more of the conditions contained in this Special Permit shall be invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired.

48. Elected or appointed Town officials or designated Town representatives shall have the right to visit the Facility during normal business hours with reasonable notice to the Company. However, this provision does not restrict the right of any appropriate Town Board or Town entity to enter the Facility at any time, without notice, to perform its designated responsibilities and obligations in its normal course of duty, although upon such entry all Town officials and/or representatives shall be subject to Facility safety requirements and procedures. All such requirements and procedures, with all updates thereof, shall be promptly provided to the Building Commissioner, Fire Chief, Police Chief, and Health Agent.

49. The Company shall have the right to assign this Special Permit to any entity solely for the purpose of financing or refinancing the Facility, furthermore, the Company shall have the right to assign the Special Permit to another entity provided that such entity has demonstrated successful technical and operational experience and financial capability to undertake the obligations of this Special Permit. Such demonstration shall be to the Special Permit Granting Authority which shall indicate its agreement or disagreement by majority vote.

50. The Company shall provide quarterly written status reports to the Board of Selectmen. These reports are intended to provide a status summary of Facility construction, operations, permit compliance, unusual incidents, citizen complaints and resolution, and other matters. The content and format shall be as agreed to by the Board of Selectmen.

51. An annual written report shall be provided to the Board of Selectmen. The Company shall present the results of the report at a public meeting scheduled by the Board of Selectmen. Copies of this annual report shall be furnished to any Milford resident making written request for same.

52. The Company shall make an immediate report of any significant incident at the Facility to the Health Agent and the Board of Selectmen.

53. A responsible Facility official will be designated as the operation's community contact. This individual will be responsible for responding to and resolving citizen complaints and inquiries.

54. In consideration for the environmental plans and procedures that must be reviewed and approved by the Town prior to issuance of a Building Permit, the Special Permit compliance testing requirements that must be demonstrated to the Town at the start of commercial operations and the technical and environmental reviews by the Town during the Facility operations period, the Company shall pay to the Town an environmental compliance review fee of $25,000 beginning 30 days after issuance of this Special Permit and to pay such amount each anniversary date thereafter throughout the development, construction and acceptance testing of the Facility equal to the previous year's payment plus five percent. Such annual increase is in lieu of any inflation adjustment.

Once the Facility has commenced commercial operations, the Company shall only be obligated to pay actual reasonable expenses incurred by the Town for such environmental reviews as described herein, up to an amount of $30,000 for the first year of facility operation and increasing by five percent per year each yearly anniversary thereafter.

55. In the event the Company is deemed to be in violation of a condition of this Special Permit, the Town shall so notify the Company in writing. The Company shall have 7 days from receipt of such notice to commence action to correct such violation or to make a retest related to such violation. If within 30 days of such notice the Company has corrected such violation or has undertaken such corrective action which by the nature of such action reasonably requires more than 30 days to complete using all reasonable efforts, or has completed such retesting to demonstrate that the Facility is then in compliance with this Special Permit, then the Company is deemed to be in compliance with this Special Permit. If, however, within 30 days of such notice the Company fails to correct the violation, or to retest and demonstrate compliance with this Special Permit, or to use all reasonable efforts to correct the violation(s)

within this time period, which may reasonably extend beyond this time period, then the Company shall be deemed to be in violation of this Special Permit and subject to any remedies at law or equity by the Town.

Further, in the event of civil and/or criminal proceedings brought by the Town to obtain compliance and/or to punish for violation, if the Town prevails as to any issue, the Company will reimburse the Town for all of its reasonable costs and expenses, including attorney, consultants, and witness fees. Failure to so reimburse will entitle the Town to order cessation of operations at the Facility.

In the event that the Town reasonably deems that compliance with the time frames above will endanger the health or safety of the public or any abutters, the Town shall have all of its usual rights under applicable law to take immediate action to obtain compliance.

56. Within all of the foregoing conditions, whenever it is indicated that the "approval" or "acceptance" of any Town employee, official, board or agency is required, the requirement for such "approval" or "acceptance" shall be deemed to be followed by the phrase, "which shall not be unreasonably withheld," and further, whenever the Town, or an employee, official, board of agency is permitted to require some test or testing procedure, such shall be deemed to be fairly and reasonably required.

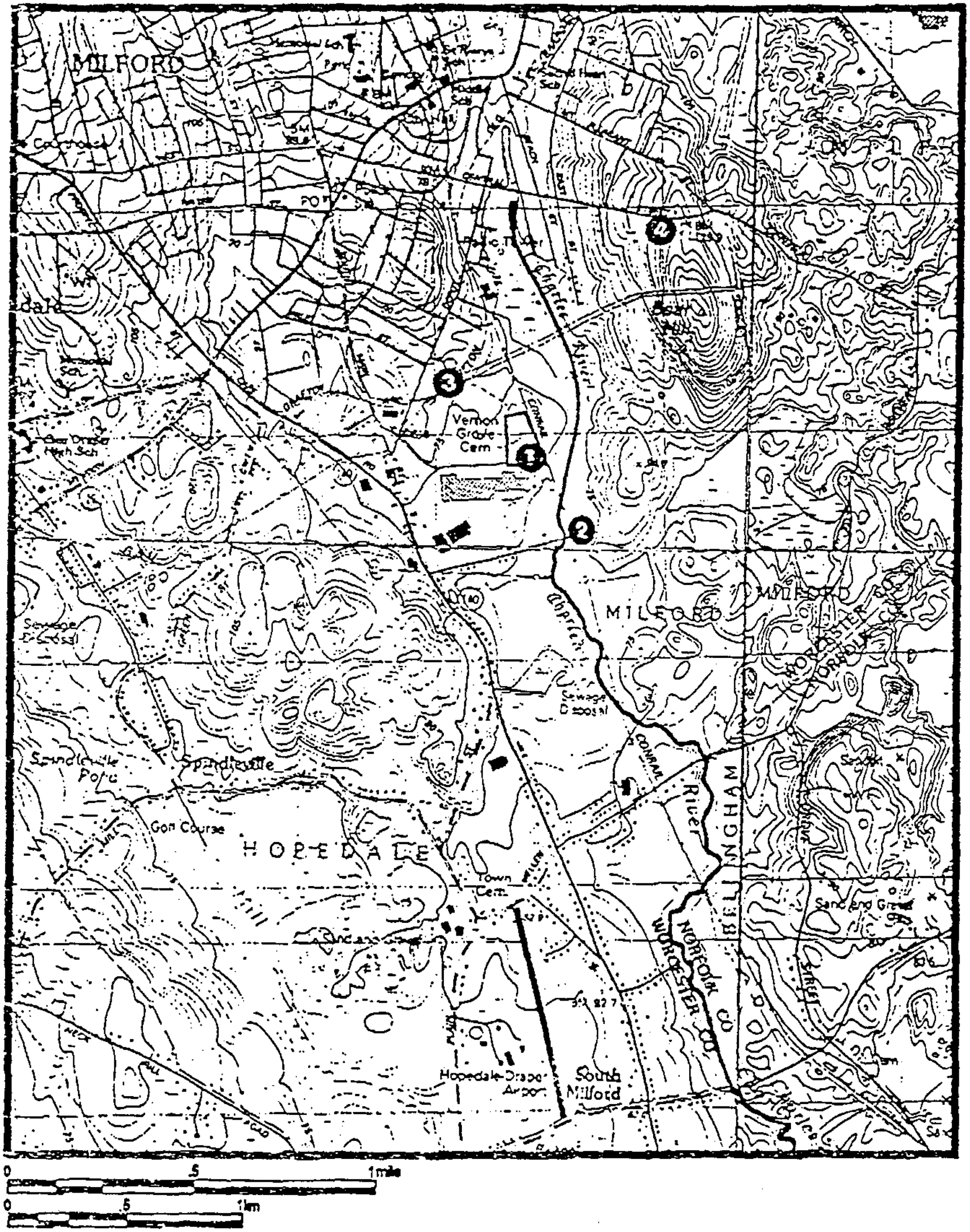
MILFORD ZONING BOARD OF APPEALS

Andrej Thomas Starkis

Andrej Thomas Starkis, Chairman

May 15, 1991

EXHIBIT A



Source: U.S.G.S. 7.5 X 15 Minute Series (Topographic Quads) of Milford, MA 1982 - Medfield, MA 1987 - Uxbridge, MA 1962 - Franklin, MA 1987

FIGURE 3.1.6-7

Noise Measurement Locations in the Vicinity

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of The Berkshire Gas Company for Approval of its Application to Construct a 2.5-Mile, 12-Inch Diameter, Natural Gas Pipeline with a Maximum Operating Pressure of 200 Pounds Per Square Inch	)	EFSC 90-29A

<u>FINAL DECISION</u>

Robert P. Rasmussen
Hearing Officer
November 8, 1991

On the Decision:

Barbara Shapiro
William Febiger

APPEARANCES: James M. Avery, Esq.
Rich, May, Bilodeau & Flaherty
294 Washington Street
Boston, Massachusetts 02108
FOR: Berkshire Gas Company
Petitioner

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FIGURES:

Figure 1: Map of Proposed Routes

The Energy Facilities Siting Council hereby APPROVES the petition of the Berkshire Gas Company to construct an approximately 2.5-mile long, 12-inch diameter, gas pipeline with a maximum operating pressure of 200 pounds per square inch along the primary route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

The Berkshire Gas Company ("Berkshire" or "Company") distributes and sells natural gas to residential, commercial, and industrial customers in 19 communities in Berkshire, Franklin, and Hampshire Counties (Exh. HO-1, p. 16). In the split-year 1989-1990, the Company had an average of 30,342 firm service customers (id., Tables G1, G2, G3A, G3B). Berkshire also sells gas to interruptible customers. The Company's total normalized firm sendout for the split-year 1989-1990 was 5,528 million cubic feet ("MMCF") (id., Table G5).

Berkshire receives pipeline gas and underground storage gas from the Tennessee Gas Pipeline Company ("Tennessee") at its Pittsfield, West Pittsfield, North Adams, Stockbridge, and Greenfield meter stations (id., p. 47, Exh. BGC-1, p. 1-1).[1] Berkshire also receives, under transportation agreements with Tennessee, pipeline gas from Boundary Gas Incorporated ("Boundary") and storage return gas from Penn-York Energy Corporation ("Penn-York") and Consolidated Gas Supply Corporation ("Consolidated");[2] and supplemental liquified natural gas ("LNG") from Bay State Gas Company and Distrigas of Massachusetts Corporation ("DOMAC") (Exh. HO-1, pp. 54-55, 56,

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1/ Berkshire's Greenfield meter station is actually located in the southern portion of Northampton.

2/ Storage return gas is a form of natural gas supply which has been removed and transported from large underground storage facilities (located in Pennsylvania and New York). Such gas supplies typically are injected into storage during the summer off-peak season and consumed during the winter heating season.

58-60). In addition, Berkshire has auxiliary propane facilities in Pittsfield, Stockbridge, North Adams, Greenfield and Hatfield.

In the most recent review of Berkshire's long-range forecast, the Energy Facilities Siting Council ("Siting Council") approved Berkshire's sendout forecast and conditionally approved Berkshire's supply plan. Berkshire Gas Company, 19 DOMSC 247, 251, 321-322, 324-327 (1990) ("1990 Berkshire Decision (Phase I)").[3,4]

The Company has proposed to construct an approximately 2.5-mile long extension to an existing natural gas pipeline in the City of Northampton. The extension would be operated at a pressure of up to 200 pounds per square inch ("psi"). The proposed project would extend the Company's existing gas main along a path that, for the majority of its distance, would run approximately parallel to an existing gas pipeline of the Company that terminates at its compressor station in the City of Northampton.[5] The proposed project would provide additional

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3/ In the 1990 Berkshire Decision (Phase I), the Siting Council imposed two conditions on the Company (19 DOMSC at 321-322). The Company responded to these two conditions on July 11, 1990 and October 10, 1990. In a letter to the Company dated December 12, 1990, the Siting Council acknowledged that Berkshire had satisfied those conditions.

4/ The Company's forecast filing also requested approval to construct pipeline and meter station facilities. On January 30, 1990, the Hearing Officer in that proceeding severed the forecast portion of the filing from the facilities portion of the filing. The Siting Council issued its decision on the forecast portion of the filing on February 9, 1990. 1990 Berkshire Decision (Phase I), 19 DOMSC at 247. The decision on the facilities portion of the filing was issued on March 16, 1990. Berkshire Gas Company, 20 DOMSC 109 (1990) ("1990 Berkshire Decision (Phase II)").

5/ The existing interconnection line is presently a 6-inch pipe, located between the Greenfield meter station and the compressor station (Exh. BGC-1, p. 1-1; Tr. 1, p. 105). The existing interconnection line was constructed in the mid 1950's (id.). The primary route of the proposed project would essentially parallel this existing pipeline (id.).

capacity in the Company's distribution system and would provide additional pipeline gas volumes to Berkshire's customers in the Greenfield and Amherst areas (Exh. BGC-1, pp. 1-1, 1-2).[6]

The Company identified three routes for the proposed project: the primary route, Alternative 1, and Alternative 2 (id., pp. 4-18 to 4-19, App. A, Exhs. 6, 7, 8). Possible interconnections between Alternative 2 and the two other routes were also identified and noticed.[7]

The primary route for the proposed project begins on Locust Street at the terminus of an existing 8-inch gas main that was installed in 1981 (approximately one-third mile northwest of Hatfield Street) (id.). From this point, the primary route travels along Locust Street southeasterly to property of the City of Northampton Department of Public Works, crosses such property northeasterly to the City of Northampton Bicycle Path ("bike path"), then follows the bike path southeasterly to the intersection of the bike path with Hatfield Street (id.). The primary route then follows Hatfield Street easterly and northeasterly to the intersection of Hatfield Street and North King Street (id.). From this point, the primary route follows North King Street northeasterly to the site of the Company's Northampton compressor station (id.). See Figure 1 for a map of the primary route.

Alternative 1 also begins at the terminus of the existing 8-inch main on Locust Street and proceeds along Locust Street

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6/ The Siting Council notes that Berkshire intends to have the proposed project on-line in 1992-1993 (Tr. 2, p. 97).

7/ The identified interconnections between Alternative 2 and the other noticed routes are (1) the segment of Bridge Road between its intersection with Hatfield Street and its intersection with Prospect Avenue, and (2) the segment of Cooke Avenue between its intersection with Hatfield Street and the point where Alternative 2 would enter the Kingsgate Plaza property (Exh. BGC-1, pp. 4-18 to 4-19, App. A, Exhs. 6,8,9).

The Siting Council's review of the Company's proposal will not include the interconnections, but will focus on the primary route, Alternative 1, and Alternative 2.

and crosses the property of the City of Northampton Department of Public Works in the same manner as the primary route (id.). Alternative 1 then follows the primary route to the intersection with Hatfield Street, then proceeds easterly along Hatfield Street to the intersection of Hatfield Street and North Elm Street, and along North Elm Street northwesterly to its intersection with Bridge Road (id.). From this point, Alternative 1 proceeds southeasterly along Bridge Road until it once again intersects with Hatfield Street (id.). Alternative 1 then proceeds along Hatfield Street and North King Street in the same manner as the primary route to the site of the Company's Northampton compressor station (id.). See Figure 1 for a map of Alternative 1.

Alternative 2 begins at the terminus of the existing 8-inch main on Locust Street and proceeds along Locust Street southeasterly to the intersection of Locust Street and Hatfield Street at which point it turns northeasterly and follows Hatfield Street to the intersection of Hatfield Street and the bike path identified in the description of the primary route (id.). Alternative 2 then follows the bike path southeasterly to its intersection with Prospect Avenue, turns northeasterly and follows Prospect Avenue to its intersection with Bridge Road, and then easterly along Bridge Road to its intersection with Cooke Avenue (id.). From this point, Alternative 2 follows Cooke Avenue northwesterly to property of the Kingsgate Plaza, then northeasterly across the Kingsgate Plaza property and North King Street and continues to the Interstate Route 91 right-of-way ("ROW") (id.). Alternative 2 then follows the Route 91 ROW northeasterly to the vicinity of the site of the Company's Northampton compressor station (id.). See Figure 1 for a map of Alternative 2.

B. Procedural History

On December 21, 1990, Berkshire filed its proposal to construct a natural gas pipeline in the City of Northampton. The facility application set forth a description of the primary pipeline route, two alternative pipeline routes, and two possible locations where segments of the routes could be interconnected to provide further combinations of routes as described above.

On February 11, 1991, the Hearing Officer issued a Notice Of Adjudication and Public Hearing and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). A public hearing was held in the City of Northampton on March 12, 1991.

The Hearing Officer conducted two days of evidentiary hearings on August 6 and 7, 1991. Berkshire presented three witnesses: Robert M. Allessio, P.E., the chief engineer for Berkshire, who testified regarding the route selection process for the proposed project and the engineering and construction aspects of the proposed project; Teresa Wong Neyhart, P.E., an associate/project manager with Almer Huntley, Jr. & Associates, Inc., who testified regarding the route selection process and the Company's efforts to address concerns relating to the route alternatives; and Les H. Hotman, vice president of gas supply, rates and marketing for the Company, who testified regarding the need for the proposed project.

The Hearing Officer entered 101 exhibits into the record, largely composed of responses to information and record requests. Berkshire entered four exhibits into the record. The Company filed its brief on September 9, 1991.

C. Jurisdiction

The Company's facility application 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 proposed facilities at a proposed site before a construction permit may be issued by any other state or local agency.

The Company's proposal to construct an approximately 2.5-mile pipeline operating at a pressure of up to 200 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.

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 present plans that address the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section II.B, below). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternative sites 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.[8] 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 a system is found to be inadequate to satisfy projected load and reserve requirements. Enron Power Enterprise Corporation, EFSC 90-101 at 10-56 (1991) ("Enron"); Eastern Energy Corporation, EFSC 90-100 at 11-75 (1991) ("EEC"); West Lynn Cogeneration, EFSC 90-102 at 7-47 (1991) ("West Lynn"); Bay State Gas Company, 21 DOMSC 1, 14-23 (1990) ("1990 Bay State Decision"); MASSPOWER, Inc., 20 DOMSC 301, 311-336 (1990) ("MASSPOWER"); 1990 Berkshire Decision (Phase II), 20

8/ 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, LNG facilities, propane facilities, gas storage facilities, energy or capacity associated with gas sales agreements, and energy or capacity associated with conservation and load management.

DOMSC at 123-132; Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 9-17 (1989) ("BECo/MWRA"); Massachusetts Electric Company and New England Power Company, 18 DOMSC 383, 393-403 (1989) ("1989 MECo/NEPCo 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"); 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. New England Power Company, 21 DOMSC 325, 334-358 (1991) ("1991 NEPCo Decision"); 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"); 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. Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo/NEPCo Decision"); Boston Gas Company, 11 DOMSC 159, 166-168 (1984) ("1984 Boston Gas Decision").

2. Description of Existing System

Berkshire introduces gas into its distribution system from two types of facilities -- Tennessee's meter stations and Berkshire's propane plants. Tennessee transports gas to

Berkshire's service territory via its principal interstate pipeline supplying Massachusetts, the Tennessee main line. In addition, two major lateral lines, the Northampton lateral and North Adams lateral, transport pipeline volumes to meter stations off the Tennessee main line in Berkshire's service territory. Berkshire receives gas from Tennessee at five meter stations, one of which is the Greenfield meter station -- the others are located in Pittsfield, West Pittsfield, North Adams, and Stockbridge (Exh. HO-R-3, p. 10).

Berkshire's service territory is divided into three service areas, the Greenfield, Pittsfield, and North Adams Divisions (Exh. HO-S-3). The proposed project will serve the Greenfield Division, which consists of the towns of Amherst, Deerfield, Greenfield, Hadley, Hatfield, Montague, and Whately, and includes approximately 6,400 customers (Exhs. HO-S-4, HO-N-1).

To supply pipeline gas to the Greenfield Division, Berkshire operates an interconnection line between the Greenfield meter station and a compressor station owned by Berkshire in northern Northampton (Exh. BGC-1, p. 1-1). The interconnection line consists of a 6-inch line that runs the full distance from the meter station to the compressor station, and a parallel 8-inch line that runs from the meter station to approximately the midpoint of the 6-inch line (id.). The proposed project would connect a new 12-inch line to the existing 8-inch line terminus (id.). The new 12-inch line would run to the Company's compressor station and thereby expand the capacity of the interconnection facilities to enhance service to Berkshire's customers in the Greenfield Division (id.).

Berkshire receives up to 8,459 thousand cubic feet per day ("Mcf/d") of pipeline volumes from Tennessee at its Greenfield meter station (Exh. HO-N-3). Beside the Tennessee volumes, Berkshire receives additional volumes transported on Tennessee's system, including pipeline gas from Boundary and storage return volumes from Penn-York and Consolidated, as well as LNG volumes that are backhauled on the Tennessee main line (Tr. 2, pp. 5, 27).[9] Berkshire has contracted with Tennessee to take up to 11,926 Mcf/d of firm pipeline deliveries at the Greenfield meter station, consisting of both Tennessee volumes and other volumes transported on the Tennessee system (Exh. BGC-1, pp. 2-2, 2-27). Berkshire also operates two liquid propane ("LP") storage and injection facilities in the Greenfield Division with a total capacity of 2,160 Mcf/d, located in Greenfield and Hatfield (id., p. 2-2).

3. Reliability

Berkshire asserted that the proposed project is needed in order to provide both reliability and economic efficiency benefits to its customers in the Greenfield Division (id., p. 1-2; Brief, p. 8).[10] Berkshire stated that it applies two reliability considerations in its gas supply planning process (1) security of supply and (2) flexibility in maximizing supply (Tr. 2, p. 59).[11]

The Company asserted that the proposed project is needed to ensure security of supply to meet forecasted sendout requirements (Exh. HO-N-5). The Company further stated that the proposed project is needed to provide the capacity to deliver the entire portfolio of its contracted supply volumes, including the newly available Northeast Expansion Project ("NOREX")

9/ The supplemental LNG supplies are vaporized by the suppliers at points on Tennessee's system east of Berkshire's territory and backhauled to Berkshire; that is, used to displace volumes being transported on Tennessee's system from points west of Berkshire's territory.

10/ The Company asserted that the proposed project would provide economic efficiency benefits. Economic efficiency benefits of the proposed project are addressed in Section II.A.4, below.

11/ Berkshire stated that it also applies an economic consideration in its gas supply planning -- dispatch on a least-cost basis (Tr. 2, p. 59).

volumes from Tennessee, to the Greenfield Division, thereby enhancing supply flexibility (Exh. BGC-1, p. 2-1).[12]

a. Sendout Forecasts

Berkshire asserted that the proposed project would provide the capacity required to meet current and forecasted customer growth in the Greenfield Division (Exh. HO-N-4). The Company explained that the Greenfield Division has been one of its more active growth areas, and the Company expects the area growth to remain fairly consistent over the next few years (Tr. 2, p. 20). The Company indicated that the 1990-1991 increase in residential customers in the Greenfield Division almost kept pace with the rate of recent years (Exh. HO-S-6, p. 5). Berkshire further stated that the Greenfield Division has relatively low gas saturation levels, thereby providing opportunity for system growth and supporting the need for

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12/ The Company argued that since the Siting Council found in the 1990 Berkshire Decision (Phase I) that the NOREX supply contributes to a least-cost supply plan, it follows here implicitly that the proposed project would contribute to a least-cost supply plan (Exh. BGC-1, pp. 1-2, 2-1) (19 DOMSC at 303). The Company further asserted that the need for the proposed project implicitly was addressed and accepted by the Siting Council since the facility was included in Table G-21 of the Company's filing in the Phase I review (id.).

The Siting Council disagrees with Berkshire's assertion that the need for the proposed project was implicity accepted by the Siting Council in Berkshire's previous forecast review. The Siting Council notes that approval of a supply plan listing future projects cannot substitute for a Siting Council determination that any particular project is needed. The information contained in supply plans provides the Siting Council with the opportunity to review planned capital additions as one component of procuring additional volumes. In addition, the finding that the NOREX volumes (or any generic volumes) contributes to a least-cost supply plan, does not constitute a blanket determination of need in support of distribution improvements anywhere in a Company's service area. NOREX was included as a system-wide supply resource in a system-wide supply plan review, while the proposed project is to be located in one division of the Company's three division service area.

expansion of pipeline capacity (Brief, p. 12).[13]

Berkshire provided projections estimating a 16.8 percent increase in firm sendout in the Greenfield Division between 1990 and 1995 (Exh. HO-RR-8). Berkshire, however, also presented demographic projections showing a 4.6 percent decrease in population from 1990 through 1995 in the Greenfield Division (Exhs. HO-1, p. 17, HO-RR-6). Berkshire explained that its projected increase in firm sendout is based on conversions of existing non-heating customers to gas heating customers, reactivation of inactive gas service lines, and conversions of non-gas residential households to gas heating or non-heating customers rather than on population growth (Exh. HO-S-8).

The Company outlined its methodology for forecasting firm sendout, which is based on its customer projections (Exh. HO-N-9). Berkshire explained that it usually forecasts sendout based on customer-specific usage levels, along with other usage factors associated with each customer class, for the most recent complete fiscal year (id.). However, Berkshire stated that since usage levels have varied widely in the last four years, it averaged customer usage over the four years to generate a more representative basis for its projections (id.). Berkshire did not provide an explanation of the variations in usage in recent years (id.).

Berkshire stated that the peak day sendout for the 1990-1991 winter was approximately 8,800 Mcf/d for the Greenfield Division (Tr. 2, p. 32). Berkshire's witness, Mr. Hotman, projected that the peak day sendout for the winter of 1993-1994 would be 9,565 Mcf/d (id., p. 35).

13/ A study entitled Residential Gas Saturation Analysis: 1980-1990, dated March 20, 1991, was prepared for Berkshire by Analysis and Forecasting, Inc. (Exh. HO-S-6). In that study, saturation refers to the ratio of residential gas customers to (1) total housing units or households in a municipality or similar area (gross saturation) or (2) those housing units or households which are accessible to a gas main (net saturation) (id.).

b. Ability of Existing System to Serve Load

The Company claimed that the existing interconnection between the Greenfield meter station and the compressor station is presently operating near full capacity during peak conditions (Exh. BGC-1, p. 2-1). The Company further stated that the present peak day distribution capacity in the Greenfield Division is 9,926 Mcf/d - including 7,766 Mcf/d of capacity through the interconnection facilities and 2,160 Mcf/d of capacity from the LP plants (id., p. 2-2).

Mr. Hotman asserted that peak day sendout would exceed the interconnection facilities' distribution capability by the 1994-1995 heating season if the proposed project is not constructed and no other option is undertaken (Tr. 2, pp. 32, 54). Mr. Hotman further stated that the system could come close to this situation during the 1993-1994 heating season (id.). He stated that the projected peak day sendout of 9,565 Mcf/d in the winter of 1993-1994, would require nearly the full capacity of the LP plants, which have a combined design capacity of 2,160 Mcf/d -- approximately 1,400 Mcf/d in Greenfield and 700 Mcf/d in Hatfield (id., pp. 35, 55). Mr. Hotman estimated that if the proposed project is not built, given the Company's forecasted growth, the Company would need to construct a peaking LP or LNG source on short notice to meet the demand of the Greenfield Division (id., p. 66).

Berkshire also stated that the Greenfield Division is currently constrained with respect to distribution of contracted pipeline supplies (id., p. 63). Berkshire asserted that presently it cannot move all of its contracted maximum daily pipeline supply volumes to the compressor station and surrounding areas to supply the Greenfield Division (Exh. BGC-1, p. 2-2).[14]

14/ The Company explained that the Pittsfield and North Adams Divisions have distribution systems that are capable of utilizing maximum delivery volumes, if needed, without any distribution constraints (Tr. 2, p. 64).

The Company stated that installation of the Tennessee NOREX facilities along the Northampton lateral allowed Tennessee to more than double the maximum allowable daily delivery of CD-6 volumes at the Greenfield meter station, from 3,884 Mcf/d to 8,459 Mcf/d (Exh. HO-N-3).[15] Berkshire further explained that the NOREX project removed delivery constraints by increasing capacity, thereby enabling greater utilization of transported volumes (Tr. 2, p. 49; Exh. HO-N-3).[16] Berkshire indicated that, with the addition of the NOREX volumes, the contracted maximum firm pipeline delivery, including CD-6 and transported volumes, to the Greenfield meter station increased from 7,351 Mcf/d to 11,926 Mcf/d (Exh. BGC-1, p. 2-2).

c. Conclusions on Reliability

The Siting Council finds that the Company has adequately shown that its projected sendout in 1994-1995 would exceed peak day distribution capability of its Greenfield Division. The Siting Council further recognizes that the operation of LP facilities near full capacity poses a significant reliability concern. Therefore, it is reasonable that Berkshire arrange for alternative solutions prior to the situation of having to depend on the LP facilities to provide a high percentage of capability on a regular basis, as is projected to occur by 1993-1994 (Tr. 2, p. 97). In addition, the proposed pipeline would address distribution constraints.

Based on the foregoing, the Siting Council finds that the Company has established that the existing pipeline system is inadequate to accommodate future system needs. Therefore, the

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15/ The Company stated it began receiving its contracted NOREX volumes in December, 1990 (Tr. 2, p. 97).

16/ Berkshire presented the most recent NOREX contract specifying 25,572 decatherms ("Dth") (24,755 Mcf/d) as the system-wide daily quantity limit, an increase of 5,096 Dth (4,933 Mcf/d) over the previous Tennessee contractual limits (Exhs. HO-R-3, HO-N-10).

Siting Council finds that additional energy resources are needed for reliability purposes.

4. Economic Efficiency

The Company asserted that the proposed project would provide economic efficiency benefits (Brief, p. 8). In particular, Berkshire asserted that the proposed project would enable the Company to dispatch greater pipeline volumes at a lower cost (id.).

In support of this assertion, Berkshire provided a supply resource dispatch analysis for its entire system with the proposed facility on line in 1992-1993, indicating that, for a normal heating season, use of propane would increase from 7 MMCF in 1991-1992 to 19 MMCF in 1995-1996 (Exh. HO-1, Table G22-N). Berkshire stated that it had not developed a separate dispatch analysis for the Greenfield Division (Exh. HO-RR-9). However, Berkshire estimated that, under the present constrained conditions of its distribution system, 9 MMCF of propane actually would be required in 1991-1992 for the Greenfield Division alone (id.). The Company further estimated that with removal of the distribution constraint in 1992-1993, only 1 MMCF of propane/LNG would be required for the Greenfield Division (id.).

In the past, the Siting Council has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and the 1984 Boston Gas Decision, 11 DOMSC at 166-168, the Siting Council recognized the benefit of adding economic supplies to a specific utility system. In its most recent review in Enron, EFSC 90-101 at 55-56, the Siting Council found that a proponent of a cogeneration project established that its project would provide economic savings of a substantial magnitude.

In this case, the Company provided data estimating that 9 MMCF of propane would be required for Greenfield alone (Exh. HO-RR-9). However, the Company indicated that 7 MMCF of propane is needed system-wide (Exh. HO-1, Table G22-N). This disparity underscores that the Company's dispatch analyses, as well as its forecast, do not reflect the existing distribution constraint. Therefore, Berkshire failed to document or support its estimates of propane usage with and without construction of the proposed project.

In addition, the Company failed to relate the economic benefit of displacing 8 MMCF of propane in 1992-1993 or any larger volumes in later years, to the $1,685,010 cost of the proposed project.

Finally, the Siting Council notes that the estimated 8 MMCF of propane displacement in the Greenfield Division is only 2 percent of the approximately 400 MMCF of such displacement Berkshire previously estimated for its overall system in 1992-1993 under the NOREX project. <u>1990 Berkshire Decision (Phase I)</u>, 19 DOMSC at 311. By contrast, Berkshire asserted that sendout in the Greenfield Division represents 25 percent of system-wide sendout in 1991-1992 (Exh. HO-RR-8).

Berkshire has not provided a clear and detailed quantifiable analysis of the actual economic efficiency benefits that the proposed project would provide in the Greenfield Division. While economic efficiency benefits are likely to be derived from the proposed project, the Company has not demonstrated that the proposed project would provide guaranteed, economic benefits of a substantial magnitude given the cost and nature of this proposed project. Accordingly, the Siting Council finds that the Company has not established that the proposed project is needed for economic efficiency purposes.

5. <u>Conclusions on Need</u>

The Siting Council has found that the Company has established that the existing pipeline system is inadequate to accommodate future system needs. The Siting Council also has found that additional energy resources are needed for reliability purposes. Additionally, the Siting Council finds that the Company has not established that the proposed project is needed for economic efficiency purposes.

Accordingly, the Siting Council finds that additional energy resources are needed.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

The Siting Council, pursuant to G.L. c. 164, sec. 69H, is required 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 [electricity or gas]; (b) other sources of electrical power or gas; and (c) no additional electrical power or gas.[17]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability. 1991 NEPCo Decision, 21 DOMSC at 359-375; 1990 Berkshire Decision (Phase II), 20 DOMSC at 133-147; BECo/MWRA, 19 DOMSC at 18-30; 1989 MECo/NEPCO Decision, 18 DOMSC at 405-424; Turners Falls Limited Partnership, 18 DOMSC 141, 166-170 (1988) ("Turners Falls"); 1988 Braintree Decision, 18 DOMSC at 25-27; Commonwealth Electric Company, 17 DOMSC 249, 279-288 (1988) ("1988 ComElectric Decision"); 1988 Middleborough Decision, 17 DOMSC at 219-224; Cambridge Electric Light Department, 15 DOMSC 187, 212-218 (1986) ("1986 CELCo Decision"); 1985 MECo/NEPCo Decision, 13 DOMSC at 141-183. The Siting Council also has required a petitioner to consider reliability of supply as part

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

of its showing that its proposed project is superior to alternative approaches.[18] 1991 NEPCo Decision, 21 DOMSC at 359; 1990 Berkshire Decision (Phase II), 20 DOMSC at 132-133; BECo/MWRA, 19 DOMSC at 25; 1989 MECo/NEPCo Decision, 18 DOMSC at 404-405.

2. Alternatives to Meet the Identified Need

The Company considered three approaches to meet the identified need: (1) the Company's proposed project; (2) expansion of existing LP facilities or construction of new LP or LNG facilities; and (3) conservation and load management ("C&LM").[19]

Berkshire's proposed project consists of construction of the proposed 2.5-mile, 12-inch, 200 psi natural gas pipeline extension from the terminus of an existing 8-inch gas main in the City of Northampton to the existing compressor station in the northern sector of Northampton (Exh. BGC-1, p. 1-1). The proposed project would provide Berkshire with firm transportation of up to 11,926 Mcf/d to the Greenfield Division (id., p. 2-2; Tr. 2, p. 27).

18/ In the 1989 MECo/NEPCo 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 also stated that gas facility proposals differ significantly from electric facility proposals with respect to reliability, and that a comparison of the reliability of alternative approaches generally will not be applicable in gas facility reviews. 1990 Berkshire Decision (Phase II), 20 DOMSC at 133 n.10.

19/ In its facility application, Berkshire lists five alternative approaches: expansion of LP facilities, construction of a new LNG facility, conservation programs, additional load management resources, and construction of the proposed project (Exh. BGC-1, p. 3-1). For the purpose of this decision, the five categories have been combined into the three approaches listed here.

With respect to the other approaches to meeting the identified need, Berkshire indicated that it considered, in a generic context, the expansion or construction of an LP facility or an LNG facility in the Greenfield Division. (Exh. BGC-1, pp. 3-3, 3-4).

In addition, Berkshire stated it would be implementing conservation programs in the Greenfield service area in the fall of 1991 as part of Phase II of its system-wide conservation program (Exh. HO-R-8). The Company also described targeted conservation and load management programs, for all three of its customer classes, with projected program lives of three years (Exh. HO-R-7).

3. Ability to Meet the Identified Need

Before reviewing the proposed and alternative approaches on the basis of cost and environmental impact, the Siting Council must determine whether each of the different approaches is capable of meeting the identified need. 1990 Bay State Decision, 21 DOMSC at 32; 1990 Berkshire Decision (Phase II), 20 DOMSC at 135; Boston Gas Company, 17 DOMSC 155, 169 (1988) ("1988 Boston Gas Decision").

Berkshire indicated that the existing interconnection facilities are presently operating near full capacity during peak conditions and are incapable of delivering the full available volumes (Exh. BGC-1, p. 2-1). The Company stated that the proposed project would enable it to deliver additional pipeline volumes on both a seasonal and daily basis in the Greenfield Division, including the newly available NOREX volumes (id., p. 1-2). Berkshire further stated that, in addition to the NOREX volumes and other Tennessee volumes, incremental volumes from Boundary Gas, Penn-York, and Consolidated would be transported via the proposed project (Tr. 2, pp. 5, 6, 27).[20]

20/ The breakdown of the total 11,926 Mcf/d volumes available to the Greenfield meter station is approximated as (footnote continued)

Berkshire asserted that the construction of the proposed project also would provide additional flexibility in dispatching the Company's supply sources (Exh. HO-N-3; Brief, p. 17).

Berkshire asserted that the proposed 12-inch pipeline size represents a balance between maximizing capacity and minimizing economic and environmental costs (Exh. HO-N-6). Berkshire stated that, in selecting a pipeline size, it aims to provide the greatest capacity at the least cost per Mcf (Exh. HO-N-13). Berkshire provided documentation demonstrating that the 12-inch diameter pipeline is the least cost per Mcf option when compared to 8-inch, 10-inch and 16-inch pipeline sizes (id.). The Company further indicated that while the 10-inch alternative is similar in cost to the 12-inch, the 12-inch pipeline provides an extra margin in terms of system pressure and growth (id.).

Berkshire stated that a new or expanded LP facility would be able to meet the need in the short term, but that such a facility's long-term reliability would be a subject of concern (Exh. BGC-1, p. 3-2). The Company asserted that the process of deriving gas volumes from an LP facility poses operational difficulties (Tr. 2, p. 33).[21] The Company further stated that although the plants can be run 24-hours a day, Berkshire would not want to run the plants continuously for an extended period of time (id.). In addition, Berkshire indicated that it is dependent on deliveries of LP via surface transportation, which is especially difficult during periods of inclement weather (id., p. 111). The Company stated that a new LNG

(footnote continued) follows: Tennessee - 8,459 Mcf; Boundary Gas - 997 Mcf; Penn-York - 1,225 Mcf; and Consolidated - 1,245 Mcf (Tr. 2, p. 27). In addition, the Company stated that the backhauled volumes from Bay State and Distrigas LNG could be transported on the pipeline (Exh. BGC-1, p. 2-3).

21/ The Company stated that the process undertaken to utilize LP consists of a series of mechanical steps, involving mixing air with propane and then mixing the vaporized propane with natural gas (Tr. 2, p. 33).

facility, as with an LP facility, could meet the need in the short run, but would also be the subject of long-term reliability concerns (Exh. BGC-1, p. 3-3). In particular, Berkshire cited the limited ability to transport LNG via trucks in inclement weather (Tr. 2, p. 111). The Company also expressed concern that permitting requirements for construction of either LP or LNG facilities would be difficult and time consuming (Exh. BGC-1, pp. 3-3, 3-4).

With respect to C&LM, Berkshire stated that it is employing conservation measures and a load management program, but that these approaches would not address reliability concerns for the Greenfield Division (id., pp. 3-1, 3-2). Berkshire presented split-year sendout tables with and without expected C&LM impacts for the Greenfield Division for the years 1992 through 1995 (Exh. HO-R-8). Berkshire projected C&LM savings of 1 MMCF in 1992, increasing to 10 MMCF in 1995 (id.). By comparison, the Company indicated that the the growth in annual sendout for the years 1991 to 1992 is projected to be 145 MMCF, and the increase from 1991 to 1995 is projected to be 285 MMCF (Exh. HO-RR-8).

The Company stated that conservation measures are an important part of its least-cost supply plan, but "could not be fully implemented in a cost-efficient timely manner" (Exh. BGC-1, p. 3-1).[22] Berkshire's conclusion that conservation measures could not be fully implemented to meet the identified need in a cost-efficient manner, was due to the magnitude of the reliability concern and the relatively low cost of pipeline gas (id.). The Company stated that while conservation would benefit the Greenfield Division in the long

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22/ The Company indicated that it is in the process of comparing each conservation program's estimated savings and societal costs with the Company's avoided costs for such savings (Exh. HO-R-2). The Company stated that verification of actual cost savings for the C&LM programs and future savings potential would be available in the next two years (id.)

run, the immediate impact of conservation would not significantly reduce the need for the proposed project (Exh. HO-R-2). In addition, Berkshire stated that accelerating the conservation program by three months in the Greenfield Division would have "little to no effect" on easing present supply constraints (Exh. HO-R-8).[23] Finally, with respect to load management, Berkshire asserted that where load management is in place to provide for peaking reserve capability, it is not meant to displace intermediate supply options such as NOREX (Exh. BGC-1, p. 3-2).

Based on the record, the Siting Council finds that Berkshire has demonstrated that C&LM cannot meet the Company's identified need in the long term. The record also demonstrates that the proposed project and the construction or expansion of LP or LNG facilities are technically capable of meeting the identified need. However, the Company has demonstrated that its proposed project is more reliable in terms of meeting the identified need in the long term.

Accordingly, the Siting Council finds that the proposed project and the construction or expansion of LP or LNG facilities are capable of meeting the identified need.

The Siting Council next evaluates the cost and environmental impacts of both the proposed project and the expansion or construction of LP or LNG facilities.

4. Cost

The cost of the proposed project for the various route alternatives ranges from $1,843,739 to $2,198,577 (Exh. HO-C-7). The Company stated that it considered all aspects of supply capability, including peaking, intermediate, and baseload types of gas supply, in determining what would

23/ The Company stated that it could not assign a cost to accelerating the implementation of the planned C&LM programs due to the insignificant benefits arising from such activity (Exh. HO-R-2).

constitute the least cost approach (Exh. BGC-1, p. 3-4). Berkshire asserted that the proposed project would address the identified needs at the least cost (id., p. 3-1).

The Company presented an economic analysis comparing an expansion of an existing LP facility, located in Hatfield, with the proposed project (id., App. F, Exh. 4).[24] Berkshire stated that the LP expansion would generally represent the least cost approach only when a limited number of days of propane use are required (id., p. 3-4). Berkshire presented documentation indicating that, for deliveries on 20 days per year or more, the cost per Mcf of expansion or construction of LP facilities would be more than that of the proposed project (id.).[25] The Company asserted that the need for an alternative supply would exceed 20 days per year based on the long term load projections for the area (Exh. HO-R-5). Berkshire further explained that pipeline gas supplies cost less than its propane supplies, and that the proposed project would allow least-cost supply in the long run (Tr. 2, p. 47). The Company noted that during the extended cold-snap of December, 1989 propane was in short supply, thereby resulting in high prices (id., p. 111).

The Company did not provide a similar analysis comparing the proposed project to the expansion or construction of a generic LNG facility. The Company did state that such an LNG facility would be more costly than the proposed project (Exh. BGC-1, p. 3-3).

24/ The figures used in the cost comparison for the expansion of the LP facility were developed by Berkshire as part of its recent base rate proceeding before the Massachusetts Department of Public Utilities (Exh. HO-RR-10; Brief, p. 15). While the expansion of the LP facility is based on calculations for expanding the Hatfield facility, the expansion could occur at either of the Company's existing LP facilities in Hatfield or Greenfield or at a new LP facility site.

25/ The Siting Council notes that the economic evaluation presented by Berkshire included a comparison of the propane expansion and the NOREX project in terms of fixed costs, Northampton expansion costs, and winter commodity costs (Exh. BGC-1, App. F, Exh. 4).

Since the Company compared its proposed project to a generic LP facility, it is difficult to make an accurate comparison of the costs of those two approaches. However, the Company did present a cost analysis that included: (1) the cost of NOREX capital improvements; (2) the cost of the proposed project; and (3) the cost of gas. Given that the cost of the NOREX capital improvements is already committed, the Company's analysis may be conservative, and may overestimate costs. Therefore, the breakeven point for selecting the proposed project over the LP facility is likely less than the stated 20 days. The Company projected the days of propane service to exceed 20 days per year.

Accordingly, based on the foregoing, the Siting Council finds that the proposed project is superior to the expansion or construction of LP or LNG facilities with respect to cost.

5. Environmental Impact

Berkshire asserted that the proposed project would minimize the impacts to residences, business, wetlands, flora, fauna, and pristine areas in the vicinity of the proposed facilities (Brief, p. 18). The Company stated that any impacts would be temporary in nature and that post-construction site conditions would be returned to pre-existing conditions (Exh. BGC-1, p. 7-1). Additionally, the Company stressed that the operation of a pipeline generally does not generate visible impacts (Brief, p. 20).

The Company indicated that the impacts associated with the construction and operation of an LP or LNG facility are greater and would last longer than those associated with the proposed project approach (Exhs. BGC-1, p. 3-3, HO-RR-11). The Company indicated that LP or LNG construction or expansion would require from nine months to a year, versus three to four months of construction for a pipeline, and that dust, noise and traffic impacts would be in effect for the entire time period in both situations (id., Exh. HO-A-9). The Company further stated that the site work for the LP or LNG facility would involve more intensive clearing and grading, creating permanent impacts to flora and fauna, and possibly wetlands (Exh. HO-RR-11). In addition, Berkshire stated that operating an LP or LNG facility would have continuous effects on surrounding areas, including visual, traffic, and noise impacts (id.).

The Siting Council notes that, although the construction impacts of an LP or LNG facility most likely would be greater than those of the proposed project, it is difficult to detail specifics when a generic facility is involved. Since the LP and LNG approaches are not site-specific, the extent of flora, fauna and wetlands to be impacted is unknown. However, the construction impacts would involve a longer overall time period and would be more permanent in nature than the short term localized impacts from the proposed project. In addition, the operation of an LP or LNG facility likely would involve more traffic, noise, and visual impacts than operation of a buried pipeline.

Accordingly, the Siting Council finds that the proposed project is superior to the expansion or construction of LP or LNG facilities with respect to environmental impacts.

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

The Siting Council has found that: (1) C&LM cannot meet the Company's identified need in the long run; (2) the proposed project and the construction or expansion of LP or LNG facilities are capable of meeting the identified need; (3) the proposed project is superior to the expansion or construction of LP or LNG facilities with respect to cost; and (4) the proposed project is superior to the expansion or construction of LP or LNG facilities with respect to environmental impacts.

Accordingly, the Siting Council finds that the proposed project is superior to C&LM or the expansion or construction of LP or LNG facilities in meeting the Company's identified need.

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 and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In order to determine whether the facility proponent has shown that its proposed facilities siting plans are superior to alternatives, the Siting Council has required a facility proponent to demonstrate that it has examined a reasonable range of practical facility siting alternatives. Enron, EFSC 90-101 at 119-126; EEC, EFSC 90-100 at 125-134; West Lynn, EFSC 90-102 at 76-85; 1991 NEPCo Decision, 21 DOMSC at 385-394; 1990 Bay State Decision, 21 DOMSC at 44-47; MASSPOWER, 20 DOMSC at 376-382; 1990 Berkshire Decision (Phase II), 20 DOMSC at 159-182; BECo/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; Altresco-Pittsfield, 17 DOMSC at 387; Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987) ("NEA"). 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. First, the facility proponent must establish that it has developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. Enron, EFSC 90-101 at 115-116, 119-124; EEC, EFSC 90-100 at 122-124, 125-133; West Lynn, EFSC 90-102 at 73-74, 76-84; 1991 NEPCo Decision, 21 DOMSC at 376-379, 385-390; 1990 Bay State Decision, 21 DOMSC at 44-47, 51-62; MASSPOWER, 20 DOMSC at 373-374, 376-382; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148-149, 151-156, 161-181. Second, the facility proponent must establish that it has identified at least two noticed sites or routes with some measure of geographic diversity.[26] Enron, EFSC 90-101 at 115-116, 124-125; EEC, EFSC 90-100 at 122-124, 134; West Lynn, EFSC 90-102 at 73-74, 84; 1991 NEPCo Decision, 21 DOMSC at 376-379, 390-394; 1990 Bay State Decision, 21 DOMSC at 44-47, 62; MASSPOWER, 20 DOMSC at 371-374, 381-382; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148-156, 181-182; Turners Falls, 18 DOMSC at 175-178; 1988 Braintree Decision, 18 DOMSC at 31-40; 1988 ComElectric Decision, 17 DOMSC at 301-303; NEA, 16 DOMSC at 381-409.

Finally, in order to determine whether the facility proponent has shown that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability, the facility 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. Enron, EFSC 90-101 at 116; EEC, EFSC 90-100 at 124-125; West Lynn, EFSC 90-102 at 74; 1991 NEPCo Decision, 21 DOMSC at 377; 1990 Bay State Decision, 21 DOMSC at 45; MASSPOWER, 20 DOMSC at 372; 1990 Berkshire Decision (Phase II), 20 DOMSC at 148; BECo/MWRA, 19 DOMSC at 38-42; Turners Falls, 18 DOMSC at 175-178.

26/ 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 the notice of adjudication published at the commencement of the proceeding.

B. Description of the Proposed and Alternative Facilities

1. Proposed Facility

Berkshire proposes to construct a 12-inch, 200 psi, natural gas pipeline extension of 2.5 miles in length, to be located along the primary route as described below (Exh. BGC-1, p. 1-1). The proposed facility would originate at the terminus of an existing 8-inch gas main that extends from the Greenfield meter station located in southern Northampton to Locust Street (id., App. A, Exh. 1). The proposed facility would continue from the terminus of the 8-inch line to the Berkshire compressor station located on North King Street (Route 5) in northern Northampton (id.).

The primary route for the proposed facility travels in a generally southeasterly direction along Locust Street and enters the Northampton Department of Public Works property; the route then turns northeasterly to the bike path, continues southeasterly on the bike path to the intersection of Hatfield Street then travels northeasterly along Hatfield Street to the intersection of North King Street (id., p. 4-18, App. A, Exh. 6). The route then proceeds northeasterly along North King Street to the existing compressor station (id.).

The cost of installing the proposed facility along the primary route is estimated to be $1,685,101 (Exh. HO-C-7).

2. Alternative Facilities

The Company has proposed two alternative routes. Both routes begin and terminate at the same location as the primary route, and like the primary route, are completely contained within the City of Northampton.

a. Alternative 1

Alternative 1 is approximately 2.8 miles in length (Exh. BGC-1, p. 4-18, App. A, Exh. 6). Alternative 1 follows the primary route to the intersection of Hatfield Street and North Elm Street (id.). The route continues in a northwesterly direction along North Elm Street to the intersection of Bridge

Road and continues east along Bridge Road to the intersection of Hatfield Street (id.). The route then proceeds along Hatfield Street and North King Street in the same manner as described for the primary route. (id.).

The cost of Alternative 1 is estimated to be $1,843,739 (Exh. HO-C-7).

b. Alternative 2

Alternative 2 is approximately 3.0 miles in length (Exhs. HO-C-1, HO-C-5). Alternative 2 extends southeasterly along Locust Street to the intersection of Hatfield Street, continues northeasterly along Hatfield Street to the Bike Path, then runs southeasterly along the bike path to the intersection of Prospect Avenue, and then continues north along Prospect Avenue to the intersection of Bridge Road (Exh. BGC-1, p. 4-18, App. A, Exh. 6). The route turns east on Bridge Road to the intersection of Cooke Avenue, then proceeds in a northwest direction along Cooke Avenue to the Kingsgate Plaza, and then travels northeasterly across the Kingsgate Plaza property to North King Street (id., p. 4-19). Alternative 2 then crosses North King Street to the Interstate Route 91 ROW, and proceeds along the ROW in a northeasterly direction to the existing compressor station (id.).

The cost of Alternative 2 is estimated to be $2,198,577 (Exh. HO-C-7).

C. Site Selection Process

Berkshire asserted that it has developed a reasonable set of siting criteria and has applied those criteria in a consistent and appropriate manner (Brief, pp. 22-23). Berkshire indicated that it reassessed its routing criteria to be certain that appropriate criteria were selected and appropriate weights were used to reflect the past stated concerns of the Siting Council (Exh. BGC-1, p. 4-1). Berkshire stated that its site selection process consisted of a three-phase analysis (id.). The three phases of this analysis were: (1) identification of as many routing areas as practicable; (2) screening the list of routing alternatives based on cost, environmental impact, and reliability; and (3) evaluating and siting of routes through a matrix of social and environmental impact factors and selecting routes (id., pp. 4-10 to 4-14). As discussed in Section III.B.2, above, the Company's site selection process yielded one primary route and two alternative routes. The following sections discuss Berkshire's development and application of its siting criteria as part of its site selection process.

1. Development of Siting Criteria

The Company stated that the criteria developed for the first phase of its analysis were intended to identify as many routing alternatives as practicable (id., p. 4-1). Berkshire determined that essentially the only criterion developed for this first phase was the ability to link the endpoints along a route of reasonable distance (id.). Berkshire explained that, generally, longer pipeline routes result in longer construction time, greater cost and greater impacts on the environment (Tr. 1, p. 82).

The Company described the screening phase as narrowing the list of alternatives based on cost and environmental impact (Exh. BGC-1, p. 4-1). The Company described the cost criteria as a consideration of construction features, mitigation features, and operating practices (id.). The Company explained that in the screening phase of the environmental analysis it attempted to minimize impacts to residences, businesses, wetlands, flora, fauna, and pristine areas (id.). The Company asserted that this phase of the analysis allowed it to identify and reject routes with excessive environmental impacts (id., p. 4-2). The Company further determined that the criterion of confining the route primarily to city streets was appropriate (id., p. 4-6). In addition, the Company assumed that due to the urban location of the existing facilities, many combinations of street routes between the facilities were possible (id.). Finally, Berkshire stated that it utilized input from city and state officials to identify environmental concerns (id., App. I; Brief, p. 24).

The evaluation and siting phase of the Company's site selection process involved developing and applying a matrix of social and environmental impact factors to compare the short term impacts of pipeline construction (Exh. BGC-1, p. 4-11 to 4-13). Berkshire stated it analyzed its social impacts based on the quantifiable factors of importance to the community which could temporarily be affected as a result of pipeline construction; and analyzed its environmental impacts based on quantifiable conditions, circumstances, and influences to the natural environment which could be affected as a result of pipeline construction (Exh. HO-A-8).

Berkshire enumerated the social impact factors as: (1) sensitive receptors, e.g., historical homes, schools, nursing homes, and hospitals; (2) traffic; (3) residential -- the number of residences affected; and (4) business -- the number of businesses affected (Exh. BGC-1, App. E, Exh. 1). The Company further enumerated the environmental impact factors as: (1) stability of soils; (2) wetlands; (3) flora; and (4) fauna (id.).

In order to evaluate route segments based on its criteria, the Company developed a ranking system for each of the impact factors on a 1-10 continuum where 0 = no impact, 5 = medium impact, and 10 = high impact (id.).[27] Berkshire further explained that all criteria were weighted equally in the context of the ranking system (id., p. 4-11). In order to evaluate the environmental impacts, the Company further asserted that it endeavored to formulate a model that could evaluate each category of impact separately, yet consider the overall impact of all the categories together (id.). The Company stated that

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27/ The scores for each of the individual impacts ranged from 1 to 10, e.g., 2,4,7, etc. (Exh. BGC-1, App. E, Exh. 1).

modeling provides a useful method for examining environmental impacts (id., p. 4-9). However, the Company acknowledged the limitations of comparing dissimilar impacts (id.).

The Siting Council notes that, in previous reviews of gas pipelines, it has accepted criteria such as those developed by Berkshire for use in the identification and evaluation of pipeline routes. The Siting Council has found previously that a range of criteria such as cost, environmental impacts, and reliability generally are appropriate for siting natural gas pipelines. 1990 Bay State Decision, 21 DOMSC at 54; 1990 Berkshire Decision (Phase II), 20 DOMSC at 162.

The Siting Council also notes that the criteria and the iterative procedure developed by Berkshire for identifying routes and ranking such routes entails the most comprehensive process that we have reviewed to date for siting facilities. For each of the criteria, the route segments were assigned relative values, determined by the potential impact the proposed project would have along that particular route segment. By doing so, Berkshire has successfully addressed the Siting Council concerns raised in previous decisions regarding the absence of weights for site selection criteria. See Enron, EFSC 90-101 at 124; EEC, EFSC 90-100 at 129; West Lynn, EFSC 90-102 at 79; MASSPOWER, 20 DOMSC at 387-379; 1990 Berkshire Decision (Phase II), 20 DOMSC at 161-162.

The Siting Council further notes that the development of numerical values and weights and the ranking of alternatives based on such numerical values and weights is a necessary step in any process for identifying and evaluating routes. However, the degree to which Berkshire assigned numerical values on a 1-10 basis may potentially place an excessive emphasis on numerical differentiation given the highly judgmental nature of the ranking system, and may yield a score based on relatively insignificant substantive differences. Therefore, a range of numerical values of fewer than 10 categories may have been more appropriate.

Nevertheless, based on the foregoing, the Siting Council finds that Berkshire has developed a reasonable set of criteria for identifying and evaluating alternative routes.

2. Application of Siting Criteria

Berkshire identified numerous routes, both on-street and off-street, that met the criterion for the first phase of the Company's site selection process (Exh. BGC-1, App. A, Exh. 3). With respect to off-street routes, the Company described three off-street pipeline routes identified during this phase: (1) a new ROW with two river crossings; (2) a pipeline route paralleling the Boston and Maine ("B&M") Railroad; and (3) overland ROWs through the Broad Brook area (id., p. 4-3).

Based on the criteria for screening sites in the second phase, however, Berkshire determined that confining the route primarily to city streets would be most appropriate for this type of facility (id., p. 4-6). In addition, Berkshire explained that the identified environmental screening criteria limited the route to existing ROWs, or routes that paralleled existing utility facilities (id., p. 4-1).[28] The Company stated that it, therefore, rejected the three non-street alternatives in the screening phase (id., pp. 4-3 to 4-6).

With regard to the on-street routes, representing numerous combinations of 15 street or street segments, Berkshire indicated it applied its phase three criteria regarding social and environmental factors to develop an overall score by street or street segment (id., p. 4-12). Based on these individual impact scores, the Company stated that it selected six possible

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28/ The Company determined that off-street alternatives involved substantial construction costs and environmental impacts (Brief, p. 25; Exh. BGC-1, pp. 4-3 to 4-6). Specifically, Berkshire stated that the new ROW with the river crossings route and the route paralleling the B&M railroad would add at least $1 million to the cost of the project due to special construction and environmental mitigation techniques (Brief, p. 25).

routes utilizing four basic corridors, which represented the straightest and shortest routes from the beginning to the end point of the proposed facility (id., p. 4-14).

Berkshire then described quantitative rankings for the six routes (id., App. E, Exh. 2). Berkshire stated that a six member study team, familiar with the study area, ranked each of the routes and developed a composite impact factor (id., p. 4-11, Exh. HO-A-3). The Company stated that each route received a ranking based on its social and environmental impact factor multiplied by the length of the segment (Exh. BGC-1, p. 4-15, App. E, Exh. 2).[29] The Company explained that it selected the three routes with the lowest overall impact score as being the most desirable with respect to the environmental impacts of pipeline construction (id., p. 4-14).[30] However, the Company asserted that the initial three routes chosen did not represent a significant degree of geographic diversity (see Section III.C.3, below, for a complete discussion of geographic diversity) and elected to alter Alternative 2 to provide greater geographic diversity and more points of interchange to allow hybrid route opportunities (id., p. 4-15).

The Siting Council notes that the Company conducted a thorough search for feasible routes for the proposed facility. The Company applied its criteria in an iterative manner to determine a workable pool of pipeline routes. The selected pool of routes was subjected to a set of quantifiable criteria, encompassing social and environmental impacts. The final results of the impact analysis directly related to the identified criteria and the stated routes.

29/ The Siting Council notes that the Company assigned lower relative values to business impacts because of the clustering of business impacts associated with the Kingsgate Plaza and the ability of traffic to bypass the affected access ways (Exh. BGC-1, p. 4-12).

30/ Finally, based on detailed analyses, the Company asserted that the routes were comparable for both cost and supply reliability (id., p. 4-16).

Based on the foregoing, the Siting Council finds that Berkshire has appropriately applied a reasonable set of criteria for identifying and evaluating alternative routes in a manner that ensures that it has not overlooked or eliminated any clearly superior routes.

3. Geographic Diversity

In this section, the Siting Council considers the second prong of the practicality test -- whether Berkshire's site selection process included consideration of site alternatives with some measure of geographic diversity. The Siting Council requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity. Enron, EFSC 90-101 at 127; 1991 NEPCo Decision, 21 DOMSC at 390-394; 1990 Berkshire Decision (Phase II), 20 DOMSC at 181-182. In addition, the Siting Council has reasoned that minor variations in routes were not sufficient to meet the Siting Council's standards regarding geographic diversity. 1991 NEPCo Decision, 21 DOMSC at 391; 1988 Braintree Decision, 18 DOMSC at 36-40. In the 1991 Berkshire Decision (Phase II), the Siting Council also stated that it does not discourage the filing of conceptually similar routes, partial route alternatives, hybrid-route alternatives, or variations where such alternatives present viable siting options (20 DOMSC at 182).

Berkshire stated that it has addressed the Siting Council considerations with regard to geographic diversity (Exh. BGC-1, p. 4-15). The Company also stated that the three proposed routes contained numerous points of interchange, providing the ability to substitute portions of one route for another (id., p. 4-16).

The record demonstrates that the primary route differs almost completely from Alternative 2 and only slightly from Alternative 1. Alternative 2 travels predominantly along different streets from the primary route, although located only a few blocks away. The Siting Council notes that considering the relatively short distance that the pipeline travels, and the initial decision to locate the pipeline along city streets, the Company has identified at least one route with some measure of diversity from the primary route. The Siting Council also notes that Berkshire has selected routes that provide ample flexibility to allow consideration of hybrid routes.

Based on the foregoing, the Siting Council finds that Berkshire has identified at least two practical routes with some measure of geographic diversity.

4. Conclusion on the Site Selection Process

The Siting Council has found that: (1) Berkshire has developed a reasonable set of criteria for identifying and evaluating alternative routes; (2) Berkshire has appropriately applied a reasonable set of criteria for identifying and evaluating alternative routes in a manner that ensures it has not overlooked or eliminated any clearly superior routes; and (3) Berkshire has identified at least two practical routes with some measure of geographic diversity.

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

D. Cost Analysis of the Proposed and Alternative Facilities

The Company estimated costs of $1,685,101 for the primary route, $1,843,739 for Alternative 1, and $2,198,577 for Alternative 2 (Exh. HO-C-7).[31] Berkshire indicated that these cost estimates included construction, engineering, permitting,

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31/ The Company had first provided a cost of $2,395,629 for Alternative 2 based on an inaccurate measurement of the route length (Exhs. BGC-1, App. F, Exh. 1, HO-C-1, HO-C-7). In addition, the preliminary cost estimates for both the primary route and Alternative 1 were lowered due to an overestimate of easement acquisition costs (id.). Since the easements were located in the segments of the routes that overlapped, both of these routes experienced a $101,502 decrease (Exh. HO-C-7).

and easement acquisition costs (Exh. BGC-1, App. F, Exh. 3).[32] The Company asserted that it expects only minor variations in the actual costs relative to the estimated costs, due to the detailed work done in developing the costs for the project (Tr. 1, p. 36).

The Company presented detailed estimates of the construction costs for the primary and two alternative routes (Exh BGC-1, App. F, Exhs. 1 and 2). The construction cost components included installation of gas mains, loaming and seeding, installation of silt fences and catch basins, removal and replacement of blacktop, pavement cuts, x-ray services, outside inspection services, and police protection (id., App. F, Exh. 3). The Company indicated that wetland replication techniques and the associated costs were necessary only for the Route I-91 segment included in Alternative 2 (Exh. HO-C-8).

Berkshire presented the location, size, and costs of the easements needed to be acquired for each route (Exhs. HO-C-4, HO-C-7). The Company stated that it does not anticipate problems in acquiring any of these easements (Tr. 1, p. 30). However, Berkshire indicated that an extended timeframe may be warranted for the bike path easement, encompassing approximately six months, since the property on which the bike path is located is presently owned by the Massachusetts Electric Company (id., p. 26). In addition, the Company indicated that it had not contacted any landowners situated along Alternative 2 with the exception of the owner of the Kingsgate Plaza (id., pp. 23-24). Berkshire emphasized that Alternative 2 easements could be acquired in approximately three months (id.). Berkshire estimated that the variance in projected easement costs could range from 15 to 20 percent (id., p. 33).

The Company indicated that use of the I-91 ROW, which is included in Alternative 2, would actually be more costly and

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32/ Berkshire indicated that, due to the inherent similarities of the routes, engineering and permitting costs would be comparable (Exh. BGC-1, p. 4-17).

time consuming than use of North King Street, which is included in the primary route and Alternative 1 (Exh. HO-A-6). The Company asserted that, although the estimated costs for the I-91 ROW were listed as less than the costs for North King Street in the cost analysis, incorporating the I-91 segment would result in increased costs not included in the estimate due to difficulties with the: (1) lack of a federally approved policy concerning the use of interstate highways for the siting of utilities; (2) existence of a suitable alternative; and (3) lack of support from the District Highway Engineer (id.).[33] Therefore, the Company stated that the problems associated with the use of the I-91 ROW would translate into increased legal and engineering costs, which were not included in the cost analysis for Alternative 2, resulting in actual costs greater than those for use of North King Street (id.).

The Company indicated that operation and maintenance costs are not included in the overall hard cost estimates (Exh. BGC-1, App. F, Exh. 3). Berkshire stated that, due to the inherent similarities of the routes, operation and maintenance costs would be comparable (id., p. 4-17). Berkshire estimated that operation and maintenance costs would be $312,150 per year, for each route, based on a capital cost of $2,500,000 for 2.5 miles. (Exh. HO-C-3).

The Siting Council notes that the Company has conducted a thorough analysis of the costs of each of the three proposed routes. Each route is broken down by segment with a detailed listing of the construction activities and the associated costs.

33/ Berkshire submitted a draft copy of a document of the Massachusetts Department of Public Works ("MDPW") submitted to the Federal Highway Administration entitled Policy on the Accommodation of Utilities Longitudinally, Along Controlled-Access Highways (Exh. HO-A-6). In this document, the MDPW states that no permit shall be granted where the MDPW determines that alternative locations for the utility facility are available, or could be implemented at a reasonable cost from the standpoint of providing efficient utility services in a manner conducive to safety, durability and economy of maintenance and operations (id.).

Accordingly, based on the Company's analysis of costs, the Siting Council finds that the primary route, Alternative 1, and Alternative 2 are acceptable with respect to costs. Further, the Siting Council finds that construction of the proposed facility along the primary route is preferable to construction along either Alternative 1 or Alternative 2 with respect to cost.

E. Environmental Analysis of the Proposed and Alternative Facilities

Berkshire stated that the three routes share similar environmental characteristics and would travel predominantly in existing ROW's through urban areas in Northampton (id., p. 8-9). Therefore, the following sections will discuss the three proposed routes as a group, indicating where the impacts differ among the routes.

1. Trees

The Company asserted that there would be no impacts to existing trees along any of the three proposed routes (Tr. 1, p. 69). The Company stated that the routes would be located predominantly in the paved roadway and that the environmental impact of the pipeline on vegetation would be limited to minimal disruption of grassy strips within the ROW (Exh. BGC-1, p. 7-3). The Company explained that its policy for protecting trees and their root systems is to move the pipeline away from the trees, wherever possible, into the paved roadway (Exh. HO-E-18).

Berkshire indicated that no trees would be removed in areas along North King Street where the primary route and Alternative 1 would be leaving the roadway (Tr. 1, pp. 62-63). Berkshire explained that, due to traffic and the repaving of North King Street in 1985, the pipeline would be aligned outside the paved surface (id.; Exh. HO-E-4). However, the Company emphasized that the pipeline would be outside the roadway only where there were no trees or utilities in the easement areas

(Tr. 1, p. 63). Berkshire also specified areas where the pipeline would be re-entering the roadway to avoid large trees along the east side of North King Street (id.). The Company further indicated that there are no trees between the proposed pipeline alignment and the roadway (id., pp. 57, 58).[34]

Berkshire stated it has retained the services of a recognized tree consultant, Dr. Tattar, who has provided tree health advice throughout the design process and would continue to assist the Company throughout the construction process (id., p. 69). The Company asserted that, based on discussions with Dr. Tattar, it would not cut any tree roots greater than one-inch in diameter, and would make every effort to maintain at least a 15-foot distance between the pipeline and mature trees (id., p. 64). The Company stated it would employ tree tunneling if root systems are encountered in the construction process, to mitigate any adverse impacts to the trees (Exh. HO-E-18).[35] The Company further provided information confirming its successful application of tree tunneling along a pipeline in Greenfield in 1986 (Exh. HO-E-27).

The record indicates that Berkshire has carefully assessed the location of existing trees along the three routes. The Company has stated that it would not remove any trees during construction of the proposed facility and would employ mitigation methods when encountering tree roots during the construction of the facility.

Based on the foregoing, the Siting Council finds that the construction of the proposed facility along the primary route,

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34/ The Siting Council notes that pipelines that run outside existing trees from a paved roadway can have significant negative impact on those trees since the roots abutting the roadway may have previously been cut or diminished from compaction, and to disturb additional roots may hasten the loss of the tree.

35/ Tree tunneling involves hand digging the roots, loosening and removing the soil with an air lance, installing the pipe, and backfilling the space around the pipe (Exh. HO-E-27).

Alternative 1, and Alternative 2, with utilization of mitigation measures, would have an acceptable impact on trees. The Siting Council further finds that the primary route, Alternative 1 and Alternative 2 are comparable with respect to impacts on trees.

2. Wetlands and Surface Water

Berkshire asserted that none of the proposed routes are located along ponds, lakes, marshes, swamps or sizeable bordering vegetated wetlands (Exh. BGC-1, p. 6-2). In addition, the Company determined that none of the proposed routes are located in the 100-year flood plain of either the Connecticut or Mill Rivers or in a groundwater contribution area for Northampton's public water supply well (id.). The Company indicated that the closest designated water supply protection zone is located 1,700 feet to the northwest of the primary route and Alternative 1, and approximately 1,600 feet from Alternative 2 (Exhs. HO-E-1, HO-E-12). The Company further stated that the project area does not contain any state-listed wetland habitat areas for rare wildlife or plants (Exhs. BGC-1, App. G, Exh. 5, HO-RR-3, Supp. D).

The Company indicated that the proposed routes would not pass directly through any known wetlands, but would be located within the 100-foot buffer zone of wetland resource areas (Exh. BGC-1, p. 6-2).[36] The Company indicated it has prepared the Notice of Intent for the City of Northampton Conservation Commission, which identifies five specific areas along the primary route where the pipeline would pass though buffer zones (Exh. HO-RR-3).[37] Berkshire listed the following

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36/ The portion of Alternative 2 along I-91 includes drainage channels that may support wetlands vegetation and may be affected by short-term construction impacts (Exh. BGC-1, App. C, Exh. 2).

37/ The areas are along Locust Street, Hatfield Street (between Bridge and Cooke Streets), and three areas on North King Street (Exh. HO-RR-3). These five areas also fall along Alternative 1. Alternative 2 is not addressed in the Notice of Intent.

erosion/siltation mitigation methods to be implemented in the buffer zone areas: (1) backfill, patch temporarily, and sweep paved areas; (2) confine the use and stockpiling of equipment and materials to the roadway limits; (3) erect siltation barriers around catch basins while the work is ongoing; (4) erect siltation barriers along sidewalks until disturbed areas are stabilized; (5) loam and seed grassy areas after construction is completed; and (6) cancel construction during actual or predicted precipitation (id.).[38]

The Company stated that the primary route and Alternative 1 both would be aligned along Hatfield Street where it crosses the Pine Brook, a location referred to as the dingle area (Exhs. HO-E-6, HO-E-22). The Company indicated that the dingle area is a hollow, or low point, on Hatfield Street where washout and flooding occurred in 1955 after a storm of a magnitude expected to recur less than once every 100 years (Tr. 1, p. 105; Exh. HO-E-6). The Company further explained that the proposed facility would be located in the roadway in this area, limiting the possibility of pipeline exposure due to washouts (Exh. HO-E-13).[39] The Company asserted that any erosion taking place in the dingle area would not affect the proposed pipeline, which would be located on the side of the road nearest the upstream slope (Exh. HO-E-22).

Berkshire indicated that the dingle area could be avoided by deviating from the primary route at Bridge Street, following

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38/ Berkshire indicated that the six mitigation methods may vary according to the specific location along the route.

39/ Berkshire indicated that a gas pipeline of the Bay State Gas Company recently was exposed in the dingle area during a severe rain storm (Exh. HO-E-22). The Bay State pipeline is located off Hatfield Street below a partially vegetated steep downstream embankment (id.). Runoff from the road and down the embankment caused erosion that exposed both the Bay State Gas Company pipeline and a water main (id.). The upstream slope, where the Berkshire pipeline is proposed, is vegetated and has a more gradual slope (id.).

Alternative 2 in a northwest direction up Cooke Avenue and meeting the primary route again where Cooke Avenue intersects with Hatfield Street (Tr. 1, p. 84). However, the Company emphasized that it does not recommend this route deviation, as it has anticipated no problems associated with the dingle area (id., p. 85). In addition, the Company asserted that this route deviation would increase traffic and residential impacts (id.). Berkshire further indicated that the Northampton Conservation Commission has expressed no special concerns regarding the dingle area, or any other specific area, along the primary route (id., p. 87).

The Siting Council notes that each route is similar with regard to the nature and extent of wetlands and surface water impacted. In addition, consistent construction procedures would be applied along each of the proposed routes to protect wetlands and surface water, and any construction impacts would be temporary in nature. However, Alternative 2 may affect dispersed wetland areas during construction necessitating temporary mitigation measures.

Based on the foregoing, the Siting Council finds that the construction of the proposed facility along the primary route, Alternative 1 and Alternative 2, with the utilization of mitigation measures, would have an acceptable impact on wetlands and surface water. Further, the Siting Council finds that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 with reference to impacts on wetlands and surface water.

3. Land Use, Traffic and Safety

Berkshire asserted that construction of the proposed facility would not necessitate the permanent removal of homes, businesses, or significant vegetative cover along any of the proposed routes (Exh. BGC-1, p. 8-6). The Company further stated that all post-construction site conditions would be equivalent to pre-existing conditions and that land use patterns would remain the same (id., pp. 7-1, 7-5).

The proposed routes are located in predominantly residential zones (suburban, medium density, and high density residential), with the exception of Kingsgate Plaza, which is zoned highway business, and the Northampton Department of Public Works property, which is zoned general industrial (Exh. HO-E-1). Berkshire stated that the primary route passes within 27 feet of the nearest residence, and all other residences are located at a minimum distance of 45 feet (Tr. 1, p. 74 [clarification filed with Hearing Officer August 23, 1991]). Berkshire stated that a total of 72 residences would be impacted by the primary route (id.). Berkshire also stated that all of the 66 residences located along Alternative 1 are more than 35 feet from this route (id.). In addition, Berkshire stated that Alternative 2 passes: (1) within 26 feet of the nearest residence; (2) within 30 and 32 feet of two other residences; and (3) at a minimum distance of 35 feet from all other residences (id.). Berkshire stated that a total of 64 residences were impacted by Alternative 2 (id.). Finally, Berkshire indicated that all routes fall within a quarter mile of two cemeteries, two nursing homes, a hospital, a school, and an elderly housing complex (Exh. BCG-1, App. B, Exhs. 1 and 2).

Berkshire stated that existing sensitive receptors are located near heavily travelled roadways, and thus would be only marginally affected by noise impacts of pipeline construction (id., p. 7-7). The Company indicated that the peak construction noise levels would be approximately 60 dBA (decibels averaged) and would not last more than three days in any one location, based on a pipeline construction rate of 500 feet per day (id.). The Company stated that there are no state regulations, nor any local noise ordinance addressing construction noise levels (Exh. HO-E-16). In addition, the Company stated that the local zoning ordinance does not address noise levels in terms of their actual decibel levels (id.). Berkshire indicated that, as necessary, it would contact affected parties to address any concerns stemming from possible noise impacts (Exh. BGC-1, p. 8-8).

The Company indicated that 80 to 88 percent of each of the proposed routes would follow significant traffic corridors, consisting of either major or minor arterial streets (id., p. 6-7). Berkshire acknowledged that short term disruption would be noticeable, and that busier streets would be most likely to experience such impacts (id., p. 8-6). The Company stated that the areas along the proposed routes that experience the heaviest traffic are located in business and industrial zones at the intersections of Locust Street and Hatfield Street, and North King Street at Kingsgate Plaza (id., p. 6-7). The Company stated that traffic problems would be greatest at street intersections, and that it would monitor these areas to prevent unacceptable traffic impacts (id., p. 7-6).

Berkshire further indicated that the most congested traffic corridors are Locust Street, Bridge Road, and North King Street, which are all major arterial streets (id., p. 6-7).[40] The Company stated that it minimized routing along Locust Street which is one of the most congested areas of traffic activity along the proposed routes (id., App. B, Exh. 4; Tr. 1, p. 82). The Company stated that the degree of traffic disruption and the appropriate mitigation techniques would be determined by traffic densities, ROW widths, and final pipeline placement (Exh. BGC-1, p. 8-7).

Berkshire noted that Northampton may experience seasonal traffic fluctuations that coincide with the beginning and end of the college school year (Exh. HO-E-14). Therefore, the Company stated that, since construction near the beginning of each of the proposed routes -- along Locust Street -- would be affected by such fluctuations, it would try to avoid commencing construction of the project at the end of May (Tr. 1,

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40/ Berkshire stated that major arterial streets are corridors characterized as carrying more than 15,000 vehicles per day (Exh. BGC-1, p. 6-7).

p. 89).[41] The Company indicated that the rate of construction along each route would be approximately 500 feet per day, and that any traffic impacts would be localized (Exh. BGC-1, pp. 7-6, 7-7). Berkshire stated that the work area typically would consist of one travel lane and the shoulder, and noted that flagmen and/or police would direct traffic in the second travel lane (id., p. 7-5).

Berkshire indicated that the MDPW is strongly opposed to placing the proposed facility within the I-91 ROW due to likely disruption of traffic (Exh. HO-A-1). Berkshire further indicated that the MDPW only allows placement of utilities in limited access highways when no other options exist (id.). (See Section III.D., n.33, above.)

In regard to safety impacts, Berkshire stated that the three routes are similar, and that no one portion of any route is more suspectible to third party damage than another (Tr. 1, p. 40). The Company further claimed that the level of traffic is not a factor in causing pipeline damage and that third party damage is usually associated with work on another utility (id.). Berkshire stated that it employs a wide variety of safeguards to protect against damage to its pipelines, including membership in Dig Safe, installation of above ground markers in ROWs and at major intersections, installation of above ground warning tapes, and utilization of test pits to locate unmarked utilities (Exh. HO-SD-3). In addition, the Company emphasized that it is working closely with the City of Northampton Department of Public Works, and that it encourages representatives from all affected utilities to observe construction of the proposed facility (Exh. BGC-1, p. 8-7; Tr. 1, p. 51).

The Company stated that it expects to have adequate clearance from all utilities on North King Street -- the segment

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41/ The Company anticipates beginning construction between April 1 and June 30, 1992 (Exh. HO-A-9).

with the greatest number of underground utilities -- as well as adequate clearance for all other route segments (Tr. 1, pp. 40-41). The Company provided the base maps used to determine the necessary distances between the pipeline and existing utilities along North King Street (Exh. HO-RR-2). Berkshire's witness, Mr. Allessio, stated that the preferred minimum distance between the proposed facility and other utilities would be five feet, but that such distances may vary according to the type of utility and the extent of maintenance associated with that utility (Tr.1, pp. 43-44). Berkshire stated that it would conduct air testing of the pipeline upon completion of the project, and would monitor the pipeline on a continuous basis using the Supervisory Control and Data Acquisition System ("SCADA") (id., p. 55; Exh. HO-SD-2).[42]

The Siting Council notes that all three proposed routes travel along urban corridors, resulting in approximately the same level of impacts to the surrounding environment, although such impacts along the I-91 segment of Alternative 2 would be unacceptable to the MDPW. In addition, the impacts would be temporary and localized in nature. Traffic impacts would be minimized through traffic control measures. Finally, the Company would utilize the required safety measures and would adequately monitor the pipeline during construction and operation.

Accordingly, based on the foregoing, the Siting Council finds that the construction of the proposed facility along the primary route, Alternative 1, and Alternative 2, with the utilization of mitigation measures, would have an acceptable impact on land use, traffic, and safety. Further, the Siting Council finds that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 with reference to impacts on land use, traffic, and safety.

42/ SCADA is a computer-based system the Company uses to monitor operation of its distribution system by monitoring pressures and load flows (Tr. 1, p. 41).

4. Conclusions on Environmental Analysis

The Siting Council has found that the construction of the proposed facility along the primary route, Alternative 1, and Alternative 2, with utilization of mitigation measures, would have an acceptable impact on trees, wetlands and surface water, and land use, traffic and safety. Therefore, the Siting Council finds that the construction of the proposed facility along the primary route, Alternative 1 and Alternative 2, with the utilization of mitigation methods, would have an acceptable environmental impact.

The Siting Council also has found that the primary route, Alternative 1 and Alternative 2 are comparable with respect to impacts on trees. Further, the Siting Council has found that the primary route and Alternative 1 are comparable, and are both preferable to Alternative 2 with reference to impacts on wetlands and surface water. Finally, the Siting Council has found that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 with reference to impacts on land use, traffic, and safety.

Accordingly, the Siting Council finds that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2, with respect to environmental impacts.

F. Reliability

Berkshire asserted that each proposed route is acceptable and comparable with respect to reliability (Exh. BGC-1, p. 4-17). The Company indicated that the reliability of the proposed routes would be comparable because the pipeline would be designed and constructed in accordance with similar operating requirements along each route (id.). The Siting Council notes that, in terms of design and construction, the placement of the pipeline along any of the proposed routes would present the same assurance of reliability. However, the opposition stated by the MDPW to placing the pipeline along the layout of I-91 most likely would impose undue permitting burdens on Alternative 2. The Siting Council stated in a previous decision that it limits

its consideration of permitting issues in its reviews of relative reliability of various alternatives to those instances where the alternatives present inherent and significant differences in the number and complexity of applicable permits. 1990 Berkshire Decision (Phase II), 20 DOMSC at 208-209. Although the number and complexity of permits required for the project would not significantly differ for the proposed routes, the ability to receive MDPW approval for Alternative 2 would be uncertain. The Siting Council notes that the primary route and Alternative 1 appear to pose little, if any, risk of permitting delays.

Based on the foregoing, the Siting Council finds that the primary route, Alternative 1, and Alternative 2 are acceptable with respect to reliability. Further, the Siting Council finds that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 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 siting alternatives.

The Siting Council has found that the primary route, Alternative 1 and Alternative 2 are all acceptable with respect to cost, environmental impact and reliability.

The Siting Council has found that the primary route is preferable to Alternative 1 and Alternative 2 with respect to cost. The Siting Council has found that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 with respect to environmental impacts. The Siting Council has found that the primary route and Alternative 1 are comparable, and both are preferable to Alternative 2 with respect to reliability.

Accordingly, the Siting Council finds that, on balance, the primary route is superior to Alternative 1 and Alternative 2 in terms of cost, environmental impacts, and reliability.

IV. DECISION AND ORDER

The Siting Council finds that the construction of an approximately 2.5-mile long, 12-inch diameter, gas pipeline with a maximum operating pressure of up to 200 pounds per square inch along the primary route 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 Berkshire Gas Company to construct an approximately 2.5-mile long, 12-inch diameter, gas pipeline with a maximum operating pressure of up to 200 pounds per square inch along the primary route, subject to the following ORDERS:

(1) Prior to commencing construction of the proposed facility, Berkshire shall (a) consult with the appropriate town officials regarding street restoration and (b) file a schedule for completing street restoration with those officials. After completing construction, Berkshire shall adhere to its schedule for restoration.

(2) Adhere to all detailed mitigation measures and assurances that were given to abutters and other persons along the route of the proposed facility with regard to activities involving possible impacts on trees along the route of the proposed facility.

The Siting Council notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal with the Siting Council. Therefore, the Siting Council further ORDERS Berkshire to notify the Siting Council of any changes other than minor variations to the proposal so that the Siting

Council may decide whether to inquire further into the issue.[43]

Robert P. Rasmussen
Hearing Officer

Dated this 8th day of November, 1991.

43/ The petitioner is obligated to provide the Siting Council with sufficient information on changes to enable the Siting Council to make this determination.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 8, 1991 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria C. Larson, Secretary of Consumer Affairs and Business Regulation; Brandt Sakakeeny (for Daniel S. Gregory, Secretary of Economic Affairs); Andrew Greene (for Susan F. Tierney, Secretary of Environmental Affairs); Chris Donodeo Cashman (for Paul W. Gromer, Commissioner of Energy Resources); and Kenneth Astill (Public Engineering Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 8th day of November, 1991

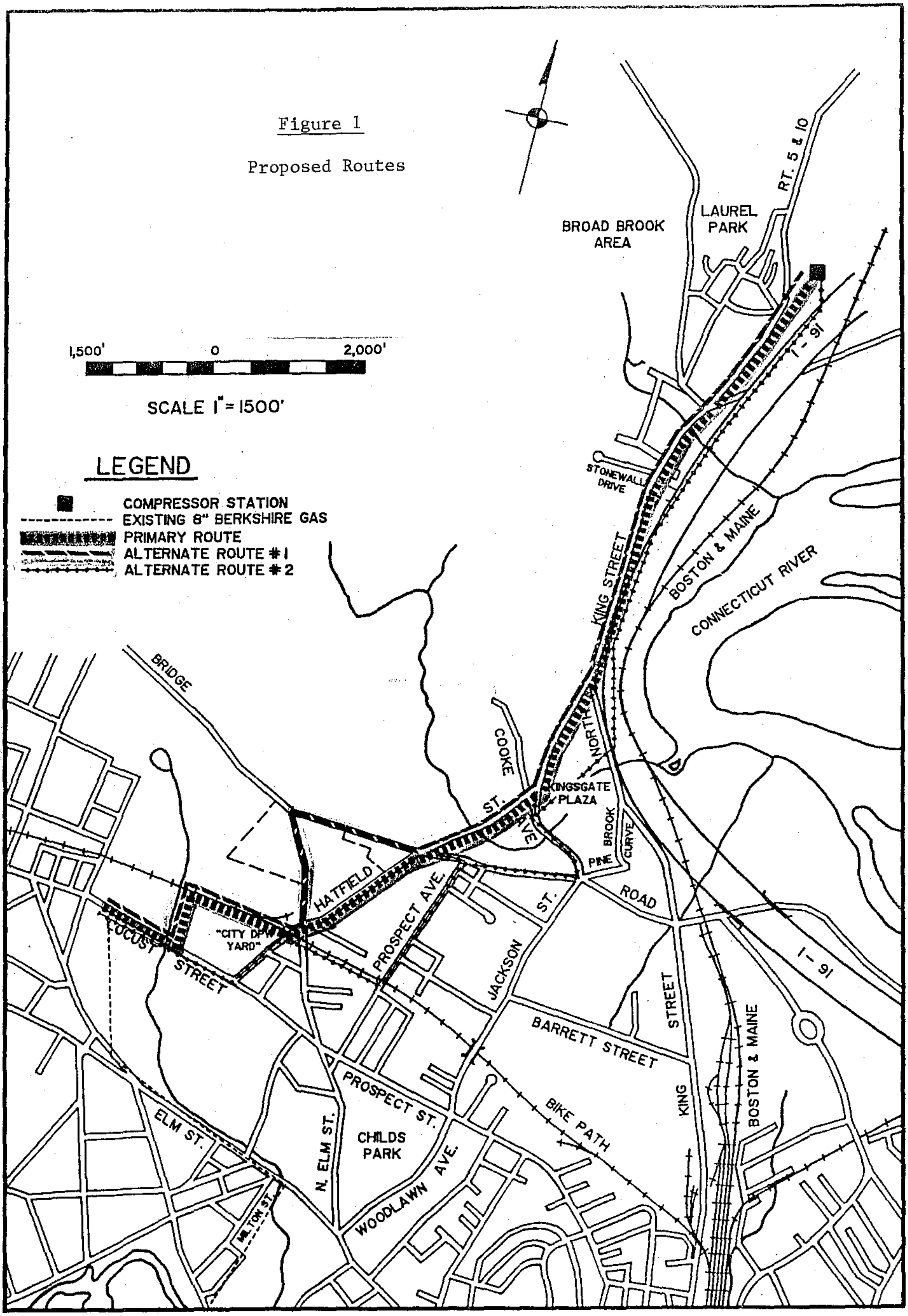
Figure 1
Proposed Routes
1,500' 0 2,000'
SCALE 1" = 1500'
LEGEND
COMPRESSOR STATION
EXISTING 8" BERKSHIRE GAS
PRIMARY ROUTE
ALTERNATE ROUTE # 1
ALTERNATE ROUTE # 2
BROAD BROOK AREA
LAUREL PARK
RT. 5 & 10
I - 91
STONEWALL DRIVE
KING STREET
BOSTON & MAINE
CONNECTICUT RIVER
BRIDGE
COOKE
NORTH
ST.
AVE
KINGSGATE PLAZA
PINE BROOK
CURVE
ROAD
HATFIELD
"CITY DPW YARD"
LOCUST
STREET
PROSPECT AVE.
JACKSON
ST.
BARRETT STREET
STREET
KING
BOSTON & MAINE
PROSPECT ST.
BIKE PATH
ELM ST.
N. ELM ST.
CHILDS PARK
WOODLAWN AVE.
MILTON ST.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Colonial Gas Company for Approval of its Fourth Annual Supplement to its Third Long-Range Forecast of Natural Gas Requirements and Resources	EFSC 89-61

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
November 8, 1991

On the Decision:

Michael B. Jacobs
Diedre S. Matthews

APPEARANCES: Jay E. Gruber, Esq.
Palmer & Dodge
One Beacon Street
Boston, Massachusetts 02108
FOR: Colonial Gas Company
<u>Petitioner</u>

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Table 1: Forecast of Firm Sendout by Customer Class
Table 2A: Lowell Division Base Case Design Year Supply Plan Heating Season
Table 2B: Cape Cod Division Base Case Design Year Supply Plan Heating Season
Table 3A: Lowell Division Comparison of Resources and Requirements Design Day
Table 3B: Cape Cod Division Comparison of Resources and Requirements Design Day

The Energy Facilities Siting Council hereby REJECTS the sendout forecast and REJECTS the supply plan filed by the Colonial Gas Company for the five years from 1989-1990 through 1993-1994.

I. INTRODUCTION

A. Background

The Colonial Gas Company ("Colonial" or "Company") distributes and sells natural gas in two operating divisions.[1] The Cape Cod Division ("Cape Division") serves approximately 48,000 customers in the towns of Wareham, Bourne, Falmouth, Sandwich, Mashpee, Barnstable, Yarmouth, Dennis, Brewster, Harwich, Chatham and Orleans (Exh. HO-1A, pp. 1, C-16, C-20, C-27). The Lowell Division serves approximately 63,000 customers in the City of Lowell and the surrounding towns of Billerica, Chelmsford, Dracut, Dunstable, North Reading, Pepperell, Tewksbury, Westford, Wilmington and Tyngsboro (id., pp. 1, L-15, L-19, L-24). In the split-year 1988-1989,[2] the Company's Cape Division firm service customers consisted of 38,887 residential heating customers, 4,165 residential non-heating customers, and 4,965 commercial and industrial customers (id., pp. C-16, C-20, C-27). In the same year, Colonial's Lowell Division firm service customers consisted of 51,528 residential heating customers, 4,444 residential non-heating customers, and 6,951 commercial and industrial customers (id., pp. L-15, L-19, L-24). Colonial sells gas to interruptible customers in both divisions (id., pp. C-29, L-26).

1/ Based on the thresholds for determining sizes of gas companies within the Commonwealth set forth in the Siting Council's Decision in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Natural Gas Utilities, 14 DOMSC 95 (1986) ("1986 Gas Generic Order"), Colonial is considered to be a medium-sized company.

2/ A split-year runs from November 1 through October 31.

Colonial's forecasts of sendout by customer class are summarized in Table 1. The Company projects an increase of total normalized firm sendout from 19,242 billion British thermal units ("BBtu") in 1989-1990 to 21,006 BBtu in 1993-1994, or an increase of approximately 9 percent over the forecast period (id., Tables G-1 through G-5).

Colonial receives pipeline gas from the Algonquin Gas Transmission Company ("Algonquin") for the Company's Cape Division and from the Tennessee Gas Pipeline Company ("Tennessee") for the Company's Lowell Division (id., p. 1). Colonial also purchases liquified natural gas ("LNG") from Distrigas of Massachusetts Corporation ("Distrigas") and Bay State Gas Company ("Bay State") (id., p. L-41). Colonial has auxiliary LNG facilities in Wareham, Tewksbury, Westford, and Wilmington and propane gas ("PG") facilities in Cataumet, South Yarmouth, Chatham, Lowell, Tewksbury, and Pepperell (id., pp. C-1, L-35).

B. Procedural History

On November 1, 1989, Colonial filed its fourth supplement to the third long-range forecast for the years 1989-1994 ("1989 Forecast").[3] On March 13, 1990, the Hearing Officer issued a Notice of Adjudication and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company confirmed notice and publication on April 30, 1990.

The Energy Facilities Siting Council ("Siting Council" or "EFSC") conducted two days of evidentiary hearings on June 10 and 11, 1991. Colonial presented five witnesses: John P. Harrington, vice president of gas supply for the Company, who testified

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3/ On November 30, 1990, the Company filed its long-range forecast for the years 1990-1995 ("1990 Forecast"). The Hearing Officer made this 1990 Forecast part of the record in this proceeding (Exh. HO-1B). While not the subject of the review in this proceeding, the Siting Council uses the 1990 Forecast to assist in its evaluation of the Company's 1989 Forecast.

regarding gas supply and forecasting matters; Thomas E. Lockett, manager of gas supply planning for the Company, who testified regarding development of the Company's forecasts; Martin C. DeBruin, a gas supply planning analyst for the Company, who testified regarding background data for the Company's filing; Patricia A. Gillette, the manager of conservation and load management ("C&LM"), who testified regarding the design, development and implementation of the Company's C&LM programs; and John L. Griffen, the director of rates and revenue requirements for the Company, who testified regarding the Company's demand-side management programs.

The Hearing Officer entered 112 exhibits into the record, largely composed of responses to information and record requests.[4] Colonial entered 8 exhibits into the record.[5] On July 26, 1991, the Company filed its brief. The Hearing Officer closed the record on July 30, 1991.

4/ In an attempt to fully develop the record with regard to the Company's least-cost analysis of its supply plan, the Hearing Officer provided the Company an additional opportunity to supplement the record following the close of hearings. (See Section III.F, below, for a discussion of the Company's least-cost supply planning process.) Tentative dates were also reserved for further hearings on the issue (see Tr. 2, pp. 129-130).

5/ Exhibits CGC-7 and CGC-8 consisted of additional responses from Mr. Harrington, which were filed on July 1, and July 30, 1991, respectively, in response to the opportunity to provide additional information with regard to the Company's least-cost analysis of its supply plan. Although the Hearing Officer offered the Company the opportunity to provide a supplemental brief on this issue, the Company elected not to file such a brief.

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

The Siting Council is directed by G.L. c. 164, sec. 69I to review the sendout forecast of each gas utility to ensure that the forecast accurately projects the gas sendout requirements of the utility's market area. The Siting Council's regulations require that the forecast exhibit accurate and complete historical data and reasonable statistical projection methods. See 980 CMR 7.02(9)(b). A forecast that is based on accurate and complete historical data as well as reasonable statistical projection methods should provide a sound basis for resource planning decisions. Boston Gas Company, 19 DOMSC 332, 340 (1990) ("1990 Boston Gas Decision"); Berkshire Gas Company, 19 DOMSC 247, 256 (1990) ("1990 Berkshire Decision (Phase I)"); Bay State Gas Company, 19 DOMSC 140, 149 (1989) ("1989 Bay State Decision"); Fitchburg Gas and Electric Light Company, 19 DOMSC 69, 76 (1989) ("1989 Fitchburg Decision"); Commonwealth Gas Company, 17 DOMSC 71, 77 (1988) ("1988 ComGas Decision"); Bay State Gas Company, 16 DOMSC 283, 288 (1987) ("1987 Bay State Decision"); Berkshire Gas Company, 16 DOMSC 53, 56 (1987) ("1987 Berkshire Decision").

In its review of a forecast, the Siting Council determines if a projection method is reasonable based on whether the methodology is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast methodology; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur. 1989 Bay State Decision, 19 DOMSC at 149; 1989 Fitchburg Decision, 19 DOMSC at 76; 1988 ComGas Decision, 17 DOMSC at 77-78; 1987 Bay State Decision, 16 DOMSC at 289; 1987 Berkshire Decision, 16 DOMSC at 55-56; Boston Gas Company, 16 DOMSC 173, 179 (1987) ("1987 Boston Gas Decision"); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986) ("1986 Westfield Decision"); Holyoke Gas and Electric

Light Department, 15 DOMSC 1, 6 (1986) ("1986 Holyoke Decision").

B. Previous Sendout Forecast Review

In its previous decision regarding Colonial, the Siting Council approved Colonial's sendout forecast and supply plan. Colonial Gas Company, 14 DOMSC 253 (1986) ("1986 Colonial Decision"). However, the Siting Council required the Company to comply with five Orders, one of which pertains to the sendout forecast:

> 1. That the Cape and Lowell Divisions report the accuracy of their five proceeding sendout forecasts using Table FA[6] and discuss the sources of inaccuracies and their implications on the reliability of their forecast methodologies. Id. at 292-293.

In addition, as Order Five of the previous decision, the Siting Council directed Colonial to comply with the Siting Council's decision in the 1986 Gas Generic Order, 14 DOMSC at 95,[7] and its implementation pursuant to Administrative Bulletin 86-1. 1986 Colonial Decision, 14 DOMSC at 293.

Colonial's compliance with Order One is discussed immediately below and Colonial's response to Order Five is discussed in Sections II.C, III.C.2, III.E.3, and III.F.2, below.

In its 1989 Forecast (Exh. HO-1A) and its 1990 Forecast (Exh. HO-1B), Colonial filed partially completed Table FA for

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6/ Table FA is designed to provide a summary of a company's historical forecast accuracy. In the table, the first column indicates the five preceding years and the second column indicates the actual normalized sendout. The remaining five columns are used to compare (in percent difference) the actual sendout with the forecasted sendout in the company's previous filings. See Administrative Bulletin 86-1.

7/ In the 1986 Gas Generic Order, the Siting Council set forth procedures applicable to gas company sendout forecasts and supply plans. The major objective of these procedures was to promote appropriate and reliable sendout forecasting and least-cost, least-environmental impact supply planning.

each division which compared each of the Company's past three forecasts with the actual normalized sendout for the year immediately following each of those forecasts (Exhs. HO-1A, pp. C-7, L-5, HO-1B, Table FA-Cape, Table FA-Lowell).[8] Table FA is intended to provide a summary of a company's long-term and short-term sendout accuracy. The Siting Council anticipated that companies would use this table as a means to review their forecasting performance and to make changes to their methodologies when appropriate. In the Siting Council's previous Colonial decision, the Siting Council provided forecast accuracy tables that compared each of the preceding five-year forecasts to the actual sendout for all of the years following each forecast for which the Company had subsequently filed this information (14 DOMSC at 263, 269). It is in this manner that the Siting Council expects Table FA to be completed.

By providing the actual sendout for only the first year following each of three past forecasts, Colonial has developed only a brief glimpse of the short-term accuracy of its forecasts. A fully developed Table FA would provide the Company with a complete understanding of its forecasting margin of error. However, in its 1989 and 1990 Forecasts, Colonial has missed this opportunity.

In addition, Order One required the Company to discuss the sources of forecast inaccuracies and their implications on the reliability of the Company's forecast methodologies (14 DOMSC at 292). In response to the Order, the Company addressed only the inaccuracy in the 1988 Forecast of 1988-1989 sendout in the Lowell Division. Specifically, Colonial explained that its assumption that several non-firm customers would convert to firm service under a change in rate structure proved to be incorrect (Exh. HO-1A, p. L-4).

8/ For example, the Company compared the forecast prepared in 1984 only to the actual sendout in the 1984-1985 year (Exh. HO-1A, p. C-7).

The Company relies on the accuracy of its forecasts of sendout to identify the need for additional resources (Tr. 2, pp. 50-53). Specifically, the Company based the acquisition of additional gas supplies on its forecast of sendout in the latter years of the forecast period (id.). However, by failing to properly identify and analyze the potential inaccuracies in its forecasts, decisions to acquire additional gas supplies were, in effect, based on incomplete and potentially inaccurate information. An analysis of potential inaccuracies would enable the Company to adjust its expectations and plan accordingly.

The Company has not provided the information required in Table FA for the five proceeding sendout forecasts nor has the Company provided a full discussion of the sources of inaccuracies and their implications on the reliability of the Company's forecast methodologies. Accordingly, the Siting Council finds that the Company has failed to comply with Order One of the 1986 Colonial Decision. The Siting Council, therefore, again ORDERS Colonial to report the accuracy of their five proceeding sendout forecasts for both the Cape and Lowell Divisions using Table FA and to discuss the sources of inaccuracies and their implications on the reliability of the Company's forecast methodologies.

C. Planning Standards

In accordance with its statutory mandate to ensure a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Council is required to review long-range forecasts of gas companies (see G.L. c. 164, secs. 69H, 69I, and 69J). The first element of the Siting Council's forecast review is a review of a company's planning standards because of their critical importance to a forecast. A company's standards are used as a basis for projecting its sendout forecast which, in turn, is used for ascertaining the adequacy and cost of a company's supply plan.

The Siting Council's review of planning standards begins with a review of a company's weather data. The accuracy of weather data is important because weather data is the basic input upon which a company's planning standards are based. The second step of our review is an analysis of the planning standards themselves -- how the company arrived at its normal year, design year and design day standards. The Siting Council reviews a company's planning standards to ensure that they are reviewable, appropriate and reliable.

1. Weather Data

The Company stated that it uses weather data collected in Bedford by the Weather Services Corporation ("WSC") for its Lowell Division (Exh. HO-F-3). The Company does not use the data that it collects at its operations facility in Lowell because it stated that the WSC data is "more consistent" (Tr. 1, pp. 47-49).[9] The Company asserted that, because Bedford lies adjacent to the Lowell Division territory, the WSC data from Bedford provides a good approximation of the weather conditions for the Lowell Division (id., pp. 48-49).

The Company indicated that for its Cape Division, it used weather data collected by WSC at Otis Air Force Base ("Otis") on Cape Cod (Exh. HO-F-3).

The Company obtains and uses degree day ("DD") data for the Lowell Division and effective degree day ("EDD") data for the Cape Division (Exh. HO-1A, pp. L-6, C-8). The Company asserted that the use of DD is sufficient for the Lowell Division, but that the Cape Division is significantly affected by wind, and, therefore, EDD is appropriate for use for the Cape

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9/ Colonial explained that it detected a discrepancy in weather data that had been collected at its facility in Lowell, which was attributed to the proximity of the measurement equipment to a water-filled gas holding tank (Exh. HO-RR-1-A). Colonial continues to collect weather data at its Lowell facility, but does not believe that the data collected prior to 1986 is reliable (id.; Tr. 1, pp. 47-49).

Division (Exh. HO-F-4). The Company stated that it had no studies of the benefits of using EDD data for either division (Tr. 1, p. 56), nor any studies justifying the continued use of DD in the Lowell Division (Exh. HO-F-13).

For the purposes of this review, the Siting Council finds that Colonial's use of the Bedford DD weather data in the Lowell Division and the Otis EDD weather data in the Cape Division is reviewable, appropriate and reliable.

Nonetheless, the Company has not fully demonstrated that its use of DD is the preferable indicator of weather effects in the Lowell Division. The Siting Council has ordered companies to pursue forecasting enhancements aggressively. See 1986 Gas Generic Order, 14 DOMSC at 104. In past decisions, the Siting Council has found that one such enhancement is the use of EDD as the primary weather indicator. See 1987 Bay State Decision, 16 DOMSC at 299; 1987 Boston Gas Decision, 16 DOMSC at 185.

In the instant case, Colonial has argued that the use of EDD is an improvement for the Cape Division, but does not use EDD for the Lowell Division. The Siting Council notes that the Company has not studied near-term and long-term forecasting methodology improvements which might result from the use of EDD in the Lowell Division as the primary weather indicator. Therefore, the Siting Council ORDERS Colonial to present in its next forecast filing: (a) an analysis of potential sendout forecasting improvements that may result from the use of EDD in the Lowell Division; (b) an analysis of the costs that would be incurred if the Company were to collect EDD from available sources; and (c) an analysis of the feasibility of using EDD in the Lowell Division.

2. Normal Year Standard

The Company derived its normal year standard for each of its divisions based on an arithmetic average of 20 years of weather data collected from September, 1968 to August, 1989 at Bedford for the Lowell Division, and at Otis for the Cape

Division (Exh. HO-1A, pp. C-8, L-6). The Company's normal year standards are 6443 DD for the Lowell Division and 6412 EDD for the Cape Division (id.).[10]

The Siting Council finds that Colonial's methodology for determining its normal year standard is reviewable and appropriate. Additionally, because the Siting Council found in Section II.C.1, above, that the Company's use of the division-specific weather data is reviewable, appropriate and reliable, the Siting Council finds that the normal year standards for the Lowell and Cape Divisions are reviewable, appropriate, and reliable.

3. Design Year Standard

In its 1986 Gas Generic Order, the Siting Council notified gas companies that renewed emphasis would be placed on design criteria "to ensure that those criteria bear a reasonable relationship to design conditions that are likely to be encountered" (14 DOMSC at 97). The Siting Council ordered each company, in each forecast filing, to include a detailed discussion of how and why it selected the design weather criteria that it uses, giving particular attention to the frequency with which design conditions are expected to recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan (id., pp. 96-97, 104-105). Further, the Siting Council explicitly ordered Colonial to comply with the 1986 Gas Generic Order in the 1986 Colonial Decision, 14 DOMSC at 290-293.

10/ In the 1990 Forecast, the Company used the September 1970 to August 1990 period and calculated the normal year standards as 6361 EDD for the Cape Division and 6450 DD for the Lowell Division (Exh. HO-1B, Table DD-Cape, Table DD-Lowell).

a. Description

In its 1989 Forecast, the Company defined its Cape Division design year standard as the coldest year within the past 20 years (Exhs. HO-1A, p. C-8, HO-F-6). Based on that definition, Colonial selected a design year standard for the Cape Division of 7396 EDD, which occurred in 1969-1970 (Exh. HO-1A, p. C-8). In its 1990 Forecast, the Company departed from its method of using the coldest year in 20 years so as to retain the 1969-1970 EDD level for its design year standard (Exh. HO-1B, p. 6). Mr. Harrington stated that the Company does not rely on any analysis to support its continued use of the 1969-1970 year as its standard (Tr. 2, p. 67). Mr. Harrington further stated that the current standard continues to be used because the Company has used the standard historically and is comfortable with it (id.). Finally, Mr. Harrington stated that when a colder than design year is experienced, the Company will consider changing its design year standard for the Cape Division (Tr. 1, pp. 59-60, 64-67).

The Company reported that it made a preliminary statistical study of the Cape Division design year standard (Tr. 2, pp. 125-128). The study indicated that, on a statistical basis, the Cape Division design year standard is colder than 98.9 percent of all years (id., pp. 5-6, 125-128). However, the Company did not provide this study or any analysis of the probability of recurrence of the Cape Division design year standard (Tr. 1, p. 26, Tr. 2, p. 125). Also, the Company did not prepare any studies of the trade-off between cost and adequacy represented by this standard, which Colonial was ordered to provide in Order Five of the 1986 Colonial Decision (14 DOMSC at 293) and the 1986 Gas Generic Order (14 DOMSC at 96-97, 105) (Tr. 1, p. 67). Instead, Mr. Harrington explained that the Company "might" conduct a thorough evaluation of the design year standard if it had to add a "large expensive block of gas or facilities" (id., p. 63), or if colder than design weather were experienced (id., p. 67). The Siting Council notes that several large blocks of gas have, in fact, been recently added to the Company's supply plan (see Section III.F, below), while no plans to review the Company's design standards were pursued (id., pp. 78-79).

With respect to the Lowell Division, Colonial stated that its design year standard of 7145 DD for this division was derived by the Company in the following manner. Colonial first calculated the twenty-year average, or "normal", monthly DD figures for each month of the year, based on data from September, 1969 to August, 1989 (Exh. HO-1A, p. L-8).[11] Second, Colonial increased each monthly average by 10 percent and identified "comparable" months in the twenty-year period (e.g., which January in the twenty years most closely matched the average January plus 10 percent) (id.). Finally, Colonial totalled the actual degree days experienced in those comparable months to arrive at the total design year DD (id.). Colonial reported, however, that two of the "comparable" months that the Company used are actually 23 years and 22 years in the past (id.). The Company noted that this empirical design year was "nearly matched (7145 DD vs. 7085 DD) 28 years ago in 1960-61" (Exh. HO-F-4).

The Company was unable to identify what factors were considered in its selection of the 10 percent level as a benchmark in developing its design year standard for the Lowell Division (Tr. 1, pp. 69-70). The Company stated only that, although it conducted a review of the coldest 12 months within the most recent 20 year period, it "is not comfortable utilizing the coldest year during that period as a design year since it is reluctant to employ a standard that is less than 10% colder than normal" (Exh. HO-F-6).

The Company provided a statistical analysis of the probability of occurrence of the Lowell Division design year standard (Exhs. CGC-2, CGC-3). In performing that analysis,

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11/ The Company did not include DD for the months of July and August in its design year standard.

Colonial assumed that DD occurrence follows a statistically "normal" distribution (Tr. 2, p. 6), and analyzed 20 years of actual DD data based on that assumption (id., p. 5). Colonial concluded by this analysis that its design year would not be exceeded in 99.5 percent of years (Exh. CGC-3).

In its analysis of the Lowell design year standard, Colonial also examined the cost impact which would result from (1) an increase of six percent and (2) a decrease of six percent in its design year standard. The Company calculated that an upward change in the design year standard raises the weighted average cost of gas by three cents per million Btu ("MMBtu") (id.). Also, when shifting down from the design year standard six percent, the cost of gas falls only one cent per MMBtu (id.). The Company concluded the downward change led to a substantial decrease in reliability for limited cost savings, while the increase in the design year standard provided only a minimal increase in reliability (Tr. 1, pp. 16-17). However, the Company did not explain how it assessed the relative reliability impact of the different design year standards.

b. Analysis

The rationale provided by Colonial for its selection of its design year standards raises several issues of concern.

First, the Company has failed to set out and consistently apply a method for determining its design year standards. In the Cape Division, the Company has abandoned its previous method of using the coldest year in 20 years in order to continue to use a particular level of EDD. Thus, the Company in the 1990 Forecast describes its standard as the actual number of EDD experienced in the 1969-1970 year -- a standard that, apparently, will be used regardless of the number of years that pass. In the Lowell Division, for which the Company stated that its procedure is to use actual DD data from the most recent 20 years the design year standard is based, in part, on months outside this 20 year period. The Company provided no explanation of why its stated procedures for determining its design year standards are not being followed, or what procedure it follows for reviewing and updating its standards. In this regard, the Siting Council can not fully review the Company's process for setting its design year standards.

Second, the Siting Council notes that Colonial's attempt to analyze the probability of occurrence of its Lowell Division design year standard through the use of its statistical model represents a significant step towards compliance with Order Five in the 1986 Colonial Decision and the 1986 Gas Generic Order. The Siting Council expects the Company to provide similar analyses of its Cape Division design year weather in future filings. Nevertheless, the Company was not able to support its assumption that the occurrence of weather in the Lowell Division follows a normal distribution curve (Exh. HO-RR-9; Tr. 2, p. 8). Such an assumption, if inappropriate, could dramatically impact the results of a recurrence analysis. The Siting Council expects a company to be prepared to justify assumptions on which it relies.

Further, Colonial presented the probabilities that it has calculated for its standards as though they represent standards that are sufficient and desirable without providing any analysis of what probability would be necessary to assure reliability. While the Company asserted that the 99.5 percent probability level for the Lowell Division is comparable to the 98.9 percent probability level for the Cape Division (Tr. 2, p. 123), Colonial provided no support for the assumption that these standards are necessary to assure, or will in fact assure, reliability for Colonial's customers. In addition, the Company failed to explain why a six percent decrease in the design year standard for the Lowell Division would result in a substantial decrease in reliability for that division. In fact, the Company has neither identified its desired design year occurrence probability level for each division, nor provided support for its assertion that the two probabilities are appropriate for the respective divisions.

Third, Colonial did not provide any analysis of its Cape

Division design year standard to support its assertion that it has appropriately balanced cost and reliability of supply. The Company has not provided any evidence that the Cape Division's design year standard does not impose any significant unwarranted supply costs. While the Siting Council notes that medium-sized companies, such as Colonial, are not required to analyze the tradeoffs between reliability and cost associated with a design year standard with the same level of sophistication as that which is expected of the largest gas companies, a medium-sized gas company must establish that it has performed a sufficient level of analysis of these tradeoffs before setting its design year standard. See 1990 Berkshire Decision (Phase I), 19 DOMSC at 264.

The 1986 Gas Generic Order emphasized the Siting Council's review of a gas company's selection of standards, and required the selection of a design year standard based on an acceptable methodology for a medium-sized company (14 DOMSC at 290-293). Although Colonial provided the various analyses and arguments described above in support of its design year standards, the Siting Council's concerns focus on the methods used by the Company to select the design year standards. The Company has failed to establish that it has developed and consistently applied an appropriate methodology to select its design year standards which is based on an adequate assessment of the appropriate level of reliability for each division as well as an assessment of the tradeoffs between cost and reliability. In sum, Colonial has not complied with Order Five in the 1986 Colonial Decision (14 DOMSC at 290-293) and the related order in the 1986 Gas Generic Order (14 DOMSC at 96-97, 104-105), in so far as both pertain to the selection of a design year standard based on an acceptable methodology for a medium-sized company.

Accordingly, the Siting Council finds that the Company's method for developing its design year standards is not reviewable, appropriate or reliable. Further, based on the record, the Siting Council finds that, although the Company's design year standards are minimally reviewable, the Company has failed to establish that its design year standards are appropriate or reliable. In making this finding, the Siting Council notes that medium-sized companies, such as Colonial, have sufficient resources to statistically analyze and/or derive design year standards. In its next filing, the Company is ORDERED to: (a) develop design year standards based on appropriately analyzed probability of occurrence criteria; (b) describe the costs associated with those design year standards and their associated reliability impacts over the forecast period; and (c) describe other probability criterion levels considered for the forecast period and their costs and reliability impacts.

4. Design Day Standard

The Siting Council's decision in the 1986 Gas Generic Order (14 DOMSC at 97) regarding the development of design criteria applies to both design year and design day standards. Likewise, the Siting Council's directive to gas companies regarding the need to consider tradeoffs between reliability and cost in establishing design standards must be applied to both design year and design day standards.

a. Description

Colonial's design day standard for the Lowell Division is 73 DD, the coldest day actually experienced by the Company in the last 23 years (Exh. HO-1A, p. L-7). The design day standard for the Cape Division is 77 EDD, and is also the coldest day actually experienced by the Company in the last 23 years (id., p. C-10).

In describing its design day standards, the Company stated "although the probability of design day recurrence was not calculated ..., the records indicate that the Cape Division design day occurred once in the last 21 years (1968) while the Lowell Division design day has occurred once in the last 9 years (1980)" (Exh. HO-F-7). Colonial also contended "that the weighted average cost of gas for the heating season varies little with changes in the design day standard of 2 percent in either direction" (Exh. HO-F-12). The Company failed to present any documentation or analysis that supports this determination (Tr. 1, pp. 93-94).

b. Analysis

The issues raised by Colonial's choice of design day standards for the Cape and Lowell Divisions are similar to those raised by Colonial's selection of its design year standards for these divisions, and prompt the same concerns -- adoption of degree day levels as standards without analysis, absence of a desired level of reliability, and failure to consider tradeoffs between cost and reliability in selection of standards -- addressed in our earlier analysis. See Section II.C.3.b, above. In essence, the Company has failed to provide the Siting Council with the evidence necessary to demonstrate that its design day methodologies or design day standards are either appropriate or reliable.

Therefore, Colonial has not fully complied with Order Five from the 1986 Colonial Decision, which required Colonial to comply with the 1986 Gas Generic Order. The 1986 Gas Generic Order emphasized the Siting Council's review of a gas company's selection of standards and required the selection of a design day standard based on an acceptable methodology for a medium-sized company (14 DOMSC at 290-293). The Company has not made a satisfactory effort to describe and analyze the effect of its design day standard on the reliability of the Company's forecast and the cost and reliability of its supply plan as required by the 1986 Gas Generic Order. As such, the Company has failed to demonstrate that its design day standard does not impose any significant unwarranted supply costs. It is essential for gas companies to explicitly analyze the tradeoffs between various levels of reliability associated with different design day standards and the costs associated with those reliability levels. Here, Colonial has provided no such analysis and has made no indication of when it would reassess its design day standards in order to determine whether the standards represent the appropriate level of reliability for a company of its size.

Accordingly, the Siting Council finds that Colonial's method for developing its design day standards is not reviewable, appropriate or reliable. Further, based on the record, the Siting Council finds that, although Colonial's design day standards are minimally reviewable, Colonial has failed to establish that its design day standards are appropriate or reliable. In making this finding, the Siting Council again notes that medium-sized companies, such as Colonial, have sufficient resources to statistically analyze and/or derive a design day standard. 1990 Berkshire Decision (Phase I), 19 DOMSC at 269. In its next filing, the Company is ORDERED to: (a) develop design day standards based on appropriately analyzed probability of occurrence criteria; (b) describe the costs associated with those design day standards and their associated reliability impacts over the forecast period; and (c) describe other probability criterion levels considered for the forecast period and their costs and reliability impacts.

5. Conclusions on Planning Standards

In previous sections of this Decision, the Siting Council has found that: (1) the Company has a reviewable, appropriate, and reliable weather database for the development of its planning standards; (2) the Company has reviewable, appropriate, and reliable normal year standards; (3) the Company's design year standards are minimally reviewable, and not appropriate or reliable; and (4) the Company's design day standards are minimally reviewable, but not appropriate or reliable. The Siting Council has also found that Colonial has not complied with Order Five in the 1986 Colonial Decision. In making these findings, the Siting Council noted its concern with basic elements of the Company's planning standards and ordered the Company to supply additional information and analyses in its next filing.

Accordingly, for the purposes of this proceeding, the Siting Council finds that, on balance, the Company's planning standards are minimally reviewable. However, the Siting Council finds that the Company has failed to establish that its planning standards are appropriate or reliable.

D. Forecast Methodologies

1. Normal Year and Design Year

a. Description

For both divisions, Colonial forecasts annual sendout under normal and design conditions for each customer class[12] by: (1) forecasting monthly usage factors[13] for existing customers from usage data from the recent historical past; (2) estimating the future monthly usage factors for new customers; (3) multiplying the projected number of existing and new customers by the appropriate projected monthly usage factors for each forecast year; and (4) multiplying the product of number of customers and their monthly usage factors by the monthly DD levels for the Lowell Division and EDD levels for the Cape Division for a normal year and a design year[14]

12/ For purposes of forecasting sendout, Colonial divides its customers into the following categories: residential heating; residential non-heating; commercial; and Otis (Air Force Base) (Exh. HO-1A, pp. C-11, C-17, C-21, C-28, L-9, L-16, L-20). The commercial category includes rate classes with heating and rate classes without heating (id.). While the Cape Division had only one rate for all commercial customers, the Company forecasted Otis separately from the rest of the commercial customers (id., pp. C-21, C-22). To forecast Otis usage, the Company relied both upon historical usage and marketing staff projections that were developed through frequent communications with Otis officials (id., p. C-26).

13/ Monthly usage factors for heating rate classes are developed by summing monthly heating usage factors and base usage factors.

14/ Monthly DD and EDD levels for both the normal year and design year are based on the Company's planning standards, which are discussed above (see Sections II.C.2 and II.C.3.a, above).

(Exh. HO-1A, pp. C-11, C-17, C-21, L-10, L-16, L-20). The four step process yields normal year and design year sendout projections on a monthly basis for each customer class for the five forecast years. Finally, the Company aggregates the monthly sendout projections to derive split-year sendout forecasts for each customer class for the five forecast years on a normal-year and a design-year basis (id.). The manner in which the Company developed each of the factors used in its normal year and design year forecast methodology is described below.

i. Usage Factors

The Company determined monthly usage factors for non-heating ("base") use for both existing and new customers in each customer rate class. In addition, the Company has two rate classes in the Cape Division and three rate classes in the Lowell Division for customers with gas heating (id., pp. C-14, C-24, L-13, L-22). The Company also determines monthly usage factors for heating use for new and existing customers in these classes. For the forecasts of all Lowell Division base use factors, Colonial used historical data from the months July and August (id., pp. L-13, L-21, L-22). For the forecast of the Cape Division base use factors, the Company used data from the months July, August and September for the residential class (id., p. C-14), and "the lowest consumption month ... either June or September" for the commercial class (id., p. C-24). The Company did not explain why September is included in its calculations for the Cape Division, but is excluded for the Lowell Division.

(A) Existing Customers

As noted above, Colonial distinguished existing customers from new customers in the preparation of its sendout forecast. The Company began its calculation of monthly usage factors for existing heating customers in the residential heating and commercial classes by identifying and separating base usage from heating usage. Colonial stated that the gas supply planning staff first calculated an average base use per heating customer by looking at ten years of historical data and choosing four, three, or two historical years of consumption data, depending on which group of years the Company judgmentally determined to be most representative of future usage (id., pp. C-14, C-24, L-13, L-22). The Company assumed that the usage not accounted for as base usage was heating usage.

To forecast the heating usage factor for existing customers, the Company evaluated the past 10 years heating usage factors for each heating rate class. The Company reviewed the heating usage factors for "significant trends that may reflect the impact of cost of gas, conservation, insulation of homes, and efficiency of new appliances" (id., p. C-11, Exh. HO-FL-9). The Company stated that it "has not done a formal study to determine to what extent the base load [and heating] trends are attributable to each of these factors" (Exh. HO-FL-9). In the Company's review of all historic usage factors, the Company seeks to "establish a trend" (Tr. 2, p. 14). The gas supply planning department, in cooperation with the marketing department, "extend[s] that established trend into the forecast period to the extent that we feel it is accurate" (id.). The Company stated "[t]here is not a statistical tool involved in the extent[ion] of the documented trends" (id., p. 15).

The Company used the same data sources and procedures in reviewing and estimating the monthly base usage factors for all rate classes' existing customers (Exhs. HO-1A, pp. C-17, C-21, L-20, HO-FL-7). The Company's extrapolation of historic usage factors in most instances was based on an average of a judgmentally selected portion of the previous ten years' usage factors to serve as the forecasted usage factor. The Company's choice of usage factors resulted in different years of data being used for the forecast of each usage factor.[15] However, in three of Colonial's nine rate classes, the Company projected usage factors to change during the forecast period (Exh. HO-1A, pp. L-18, L-23, C-25).[16] The Company's technique to project these varying usage factors necessarily differed, but the Company did not provide an explanation of how the projections were made.[17]

Once base usage and monthly heating usage factors were developed for each rate class, the Company then divided heating

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15/ For example, to forecast the residential heating customers heating usage factor for the Cape Division, the Company used the average of the most recent four years' heating usage rates as the projected heating usage factor (Exh. HO-1A, p. C-15). The Company stated that it made this estimate through a review of the "relatively consistent" sendout pattern over the past several years, and by assuming that the existing housing stock on the Cape was "relatively new" (id.).

To establish base use for commercial customers in the Lowell Division, the Company used July and August data from the past ten years, subjectively choosing three years of data for the G-1 rate class, and four years of data for the G-2 rate class (id., pp. L-20, L-22 to L-23). In its Lowell Division forecast, as in all of its usage factor forecasts, the Company graphed the historic data to identify trends for use in forecasting (Tr. 2, pp. 14-15).

16/ The Siting Council notes that the Company forecasted its three Lowell Division commercial rate classes separately, and prepared an aggregated commercial and industrial forecast for Siting Council review (Exh. HO-1A, pp. L-21, L-22). In future filings the Siting Council directs Colonial to provide forecasts disaggregated by customer type, especially where industrial customers are identifiable. The Siting Council also requests identification of industrial customers by 2-digit SIC codes. See 980 CMR 7.06(7)(c); Colonial Gas Company, 11 DOMSC 111, 124, 145 (1984).

17/ The Company described its forecast of base usage in the Lowell non-heating residential rate class as decreasing less than one percent per year, its forecast of heating usage for the Lowell G-3 commercial rate class as decreasing five percent per year, and its forecast for the Cape commercial rate class as beginning with the most recent two-year historical average base usage factor, and rising to the most recent four-year historical average base usage factor.

usage and base usage by the number of customers in that class for each month to estimate heating use per customer and base use per customer for that month (id., p. C-11). The Company's calculation of the base use per customer per day and the heating use per customer per degree day (or per EDD for the Cape Division) for each month were used to develop the forecast for existing customers (Exh. HO-FL-3).

The Company argued that its method of considering all "significant trends" is sufficient to capture price responses and economic activity (Exh. HO-1A, p. C-21). The Company supported this claim by relying on an observation of consumption following a price increase.

> [T]he Company did not see a significant change in consumption patterns after the institution of seasonal rates in November of 1988. The consumption patterns were monitored to determine if the higher winter rates would result in more conservative use per customer. The fact that traditional trends were not significantly altered, reinforces the conclusion that other influences upon consumer use, such as employment and inflation characteristics, also have a meaningful influence upon consumption. (emphasis added) (id., pp. 6-7).

However, despite this statement, the Company's current forecasting methodology does not directly or systematically incorporate such meaningful influences as employment, inflation or conservation.[18] The Company further stated that it is unsure that the benefits that would be realized by incorporating these exogenous variables would warrant the costs (id.).

18/ Colonial stated that it gathers "general economic" information from: (1) chambers of commerce; (2) planning and economic development commissions; (3) industry associations; and (4) business publications and local media (Exh. HO-FL-10). However, the Company did not explain how usage factors were adjusted to reflect this information.

(B) New Customers

The Company employed a variety of procedures in estimating the monthly usage factors for new customers. Future customers' consumption characteristics were provided by the marketing department, in part through their collecting and reporting of projected consumption patterns of newly added customers (Tr. 2, p. 25). These characteristics were then used by the Company to develop monthly usage factors for new customers.

In the Lowell Division, new residential heating customers are judged to be one of four types (condominium, conversion, apartment, or single family home) (Exh. HO-1A, p. L-9). The supply planning department determines the new base and heating use factors for each of these four types by examining a survey of new customers added over an unidentified historical period (id.). In the Cape Division, the Company estimated new residential customers' base usage to be 25 million Btu per year ("MMBtu/year") less than existing customers base usage (id., p. C-15). With this assumption, Colonial forecasted the gradual decline of base use for the Cape Division due to the influence of new customers (id.). The Company provided no justification or explanation as to why it uses different approaches to determine residential customer usage factors for its two divisions.

For the Lowell commercial class, Colonial did not indicate how it forecast new customer usage factors. Instead, the Company discussed the relative "attractiveness" of its commercial rates (id., pp. L-20, L-21), and its observations of the type of new commercial customers in the division (id., pp. L-22, L-23). For the Cape Division's commercial class, the Company explained that its "analysis of new customer consumption for this class does not provide reliable data that can be independently applied to all commercial customer additions" (id., p. C-25). Therefore, the Company's forecast for the Cape's commercial customers' base usage and heating usage factors for new customers assumes the same use as that for existing customers (id.).

ii. Projected Customer Numbers

The Company developed projections of customer numbers based on: (1) service area data and growth expectations developed by Colonial's marketing representatives; (2) influences on the gas market reflected in publications and by associations -- ranging from chambers of commerce to utility organizations; and (3) decisions made by relevant bodies -- ranging from local planning boards to the Massachusetts Department of Public Utilities -- and federal tax code changes (Exh. HO-FL-10). The Company stated that its service area data and internally developed growth expectations were the principal source and starting point for its customer forecast, while the secondary sources served as a supplement when the Company determined that information to be relevant (Exh. HO-FL-2). Mr. Harrington explained that Colonial's marketing department has data and techniques "to support their opinions" regarding customer numbers, but no information was provided in support thereof, or describing how that data is collected or analyzed (Tr. 2, pp. 16-17; see also Exh. HO-FC-8).

The Company did provide examples of sales forecast reports prepared by its marketing departments (Exhs. CGC-4, CGC-5). The Company's sales forecast reports consist of projections of total annual number of customers and annual growth rates by rate class (id.). The Cape Division report made projections for five years (Exh. CGC-4), while the Lowell Division report projected customer data for six years (Exh. CGC-5). Mr. Harrington explained that the marketing reports are designed by the supply planning department to provide information required by that department (Tr. 1, p. 32). Mr. Lockett added that the marketing department provides average numbers of customers on a monthly basis (id., p. 34), although the examples provided by the Company show annual figures only (Exhs. CGC-4, CGC-5). Mr. Harrington described the examples provided by stating "the numbers that are provided by the respective marketing departments ... reflect ... the percent change year to year" (Tr. 1, p. 36). The Company demonstrated that it maintains historic monthly data, by rate class, of the number of customers for use in estimating future numbers of customers (Exh. HO-FL-3). However, the record is not clear as to how the Company actually uses this information to project monthly numbers of customers, or how the monthly numbers are developed.

b. Analysis

The Siting Council notes that Colonial's overall methodology for forecasting normal year and design year sendout -- forecasting base and heating usage factors and number of customers -- is generally appropriate for a medium-sized gas company. However, the Company's development of forecasts of each of the primary components of its overall forecast raise significant concerns, which are addressed below.

i. Usage Factors

The Company's calculation of usage factors for each customer class relies substantially on judgment of the proper historical period to use as the predictor of future usage. The Company selects a different subset of the past ten years' usage factors for each rate class depending on the Company's expectations of what future usage will be. The Company selects different historical periods based on "a feeling ... for historical progression" of the data when the data is "plotted graphically" (Tr. 2, pp. 14-15). The Company has a single exception to this approach, i.e., use of its survey of recent customers in the Lowell residential heating class in the development of usage factors for new customers. However, the Company's use of this survey for only new customers of one of its many customer classes is neither explained nor justified. The Company's reliance solely upon judgment to select the historical period and, in effect, the usage factors, for all other classes has also not been justified.

In the review of other medium-sized gas company's forecast filings, the Siting Council has criticized these companies for failing to provide the formulas used in calculating, or to otherwise fully document its choice of, usage factors and customer numbers. Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 48-49 (1986) ("1986 Fitchburg Decision"); Berkshire Gas Company, 14 DOMSC 107, 122 (1986) ("1986 Berkshire Decision"); Fitchburg Gas and Electric Light Company, 12 DOMSC 173, 178 (1985) ("1985 Fitchburg Decision"). For example, in the 1986 Fitchburg Decision, the Siting Council reiterated its criticism -- made in response to Fitchburg's previous filing -- of Fitchburg's forecast methodology as it failed to appropriately link historical data to future projections (15 DOMSC at 48). In the 1989 Fitchburg Decision, the continued failure of Fitchburg to provide such documentation, in addition to Fitchburg's failure to justify other assumptions contained in its forecast methodology, resulted in a Siting Council finding that, on balance, Fitchburg had not established that its forecasting methodologies for the normal year and design year were appropriate (19 DOMSC at 91).[19] In that decision, the Siting Council noted that the lack of sufficient supporting documentation alone can lead to a rejection of a sendout

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19/ In the 1987 Berkshire Decision, although Berkshire provided (1) an explanation of how it calculates usage factors, and (2) documentation regarding customer number projections and customer use factor adjustments, the Siting Council noted that Berkshire had failed to establish that its customer growth projections were based on reliable data (they were provided through "conversations with the Company's Marketing Department") or that its assumptions regarding the effects of conservation were appropriate (16 DOMSC at 62-63). In that decision the Siting Council found that Berkshire's forecast methodology was neither appropriate nor reliable. Id. at 64, 67.

forecast. Id. at 90.[20]

Siting Council regulations require, at a minimum, that forecasts allow for the identification of significant determinants of future sendout. See 980 CMR 7.06(5). Further, in the 1986 Colonial Decision, the Siting Council encouraged Colonial to refine its forecast methodology and indicated that improvement was needed specifically in: (1) determining which variables have significant effects on sendout; (2) estimating those variables; and (3) performing sensitivity analyses using those variables (14 DOMSC at 264).

The Siting Council finds that Colonial has failed to establish that its methodology for forecasting usage numbers is reviewable, appropriate, or reliable. Accordingly, the Siting Council finds that Colonial's forecast of usage numbers is not reviewable, appropriate or reliable. The Siting Council, therefore, ORDERS Colonial, in its next filing, to: (a) fully describe the methodology used to develop its projection of usage factors; (b) provide complete documentation of the assumptions used in its forecasts of usage factors; (c) fully describe its methodology for identifying and selecting variables on which its forecasts of usage factors are based; and (d) perform sensitivity analyses based on inclusion of variables identified in (c) above.

ii. Projected Customer Numbers

The Company's sendout forecast is largely impacted by its projections of customer numbers which are primarily based on information provided by its marketing department. While the Company stated that its forecast of customer numbers involves some application of judgment in the evaluation of competition,

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20/ The Siting Council also notes that its regulations require a company to employ reasonable statistical methods in its forecast methodologies and that those methodologies be able to accommodate sensitivity testing and quantify various factors such as federal and state conservation programs and improved appliance efficiency standards. 980 CMR 7.02(9)(b) and 7.09(2).

construction activities, and economic trends, the Company was unable to describe how specifically these factors were integrated in the development of the growth numbers (Tr. 2, p. 19). Furthermore, while the Company indicated that economic activity, conservation and competition from other fuels are relevant to customer projections, its methodology fails to include any of these elements as part of a comprehensive process. While the Company indicated that a wide variety of information sources and types of information were relied upon (Exh. HO-FL-10), the Company has not explained any procedure that is used in either of its two divisions to assemble this information, analyze it, and adjust growth numbers accordingly. The Company witnesses also failed to explain how the annual growth numbers provided by the marketing department are transformed into the critical monthly customer numbers in the estimation of sendout.

Siting Council regulations require, at a minimum, that forecasts allow for the identification of significant determinants of future sendout. See 980 CMR 7.06(5). Further, in the 1986 Colonial Decision, the Siting Council encouraged Colonial to refine its forecast methodology and indicated that improvement was needed specifically in: (1) determining which variables have significant effects on sendout; (2) estimating those variables; and (3) performing sensitivity analyses using those variables (14 DOMSC at 264).

The Siting Council finds that Colonial has failed to establish that its methodology for forecasting customer numbers is reviewable, appropriate, or reliable. Accordingly, the Siting Council finds that Colonial's forecast of customer numbers is not reviewable, appropriate or reliable. The Siting Council, therefore, ORDERS Colonial, in its next filing, to: (a) fully describe the methodology used to develop its projection of customer numbers; (b) provide complete documentation of the assumptions used in its forecasts of customer numbers; (c) fully describe its methodology for identifying and selecting variables on which its forecasts of customer numbers are based; and (d) perform sensitivity analyses based on the inclusion of variables identified in (c) above.

iii. Conclusions on Normal Year and Design Year Forecast Methodology

The Siting Council has found that Colonial has failed to establish that its methodologies for forecasting usage factors and customer numbers are reviewable, appropriate or reliable. Accordingly, the Siting Council finds that Colonial has failed to establish that its normal year and design year forecast methodologies are reviewable, appropriate or reliable.

2. Design Day

a. Description

The Company projected design day sendout in a similar manner to its projections of annual sendout -- using base usage and heating usage factors projected for each class of customers times the number of customers in that class. The Company used its normal year, monthly usage factors from the month of January, divided evenly into a use per day factor (Exh. HO-1A, pp. C-51, L-48). In addition, Colonial assumed that the number of customers on the peak day in each year of the forecast period would be equal to the average number of customers projected for each rate class for that January (id.). The Company asserted that this assumption is justified as there is an insignificant variation in the number of customers during the month of January (Exh. HO-FC-7).

The Company contended that normal January base usage and heating usage factors were reasonable because: (1) January tends to be the coldest month; (2) actual peak days have occurred in January; and (3) January is in the middle of the heating season, noting "[t]he proclivity of MMBtu/EDD patterns to be erratic going into and coming out of the heating season" (Exh. HO-1A, p. C-51). The Company further indicated that it projects January to have the highest base usage and heating usage factors across all its customer classes (Tr. 1, p. 12). The Company also supported its design day methodology by indicating that it does not apply a linear relationship between weather and sendout (Exh. HO-F-16). Instead, the Company emphasized that its forecast is based on monthly average heating usage factors that are specific to the month in which the peak day is most likely to occur (Exhs. HO-1A, p. C-51, HO-F-14).

b. Analysis

The Company's design day forecast methodology begins with the customer number and usage factor forecasts described above (see Section II.D.1, above). The Company adapts these forecasts to develop its forecast of design day sendout by using the January components of the annual forecasts.

The Company forecasts on the basis of a varied sendout response to weather. However, the Company has calculated this response only to a level of detail represented by monthly averages. For the design day, the Company, therefore, uses a monthly average response to cold weather when forecasting the sendout for the coldest anticipated weather. As a result, by using its January usage factors for its design day forecast, the Company has assumed that customer usage patterns on a design day are no different than on an average January day in a normal year. Yet, the Company itself has determined that use per degree day is higher during colder weather (Exh. HO-F-16). For example, in its cold-snap analysis, the Company employs January usage factors to reflect higher use per customer per degree day and increased consumption during colder weather (Tr. 1, p. 12) (see Section III.E.3, below). In effect, the Company has failed to fully apply the fundamental concept behind its forecasts of annual sendout -- that use varies with weather -- to its forecast of design day sendout. It is the design day sendout forecast which is the most dependent on this relationship. Accordingly, the Siting Council finds that the Company has failed to establish that its reliance upon normal year usage factors in projecting design day sendout requirements is reviewable, appropriate or reliable for estimating design day needs. The Siting Council, therefore, finds that Colonial has failed to establish that its design day forecast methodology is reviewable, appropriate or reliable.

In addition, the Siting Council has found that the Company's annual customer number and usage factor forecasts are not reviewable, appropriate or reliable (see Section II.D.1.b.i. & ii, above). Accordingly, the Company's reliance on these forecasts renders its design day forecast not reviewable, appropriate or reliable. Furthermore, the Siting Council ORDERS Colonial in its next filing to (a) develop and apply a new design day forecast methodology or (b) fully document its assumptions regarding the relationship between monthly heating usage factors in normal weather and daily heating usage factors in design weather.

3. Conclusions on Forecast Methodologies

The Siting Council has found above that the Company's normal year and design year forecast methodologies are not reviewable, appropriate or reliable. The Siting Council has also found that the Company's design day forecast methodology is not reviewable, appropriate or reliable. In making these findings, the Siting Council noted its concerns with elements of the Company's forecast methodologies and ordered the Company to make improvements in its next filing.

Accordingly, the Siting Council finds that the Company has failed to establish that its forecast methodologies are reviewable, appropriate or reliable.

E. Conclusions on the Sendout Forecast

The Siting Council has found that the Company's planning standards are minimally reviewable, and not appropriate or reliable. The Siting Council has also found that the Company has failed to establish that its forecast methodologies are reviewable, appropriate or reliable.

While the Siting Council regulations do not specify methodologies companies must use, certain minimum standards are required. The Siting Council regulations state that forecast methodologies must accommodate sensitivity testing of major assumptions, and explicitly quantify responses to price and actual changes in rate structure. <u>See</u> 980 CMR 7.09(2). The Company's approach to forecasting customer numbers and usage factors fails to satisfy the Siting Council's regulations. The Company's use of judgment to find trends without the use of any objective procedures does not meet the Siting Council's requirement that the Company employ reasonable statistical projection methods. The forecasting techniques of the Company, and the Company's failure to correctly report the accuracy of its previous forecasts across the period relevant to resource acquisitions (see Section II.B, above) raises concerns about the Company's ability to provide a needed energy supply at the lowest possible cost.

Accordingly, the Siting Council REJECTS Colonial's forecast of sendout requirements.

II. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

The Siting Council is charged with ensuring "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. In fulfilling this mandate, the Siting Council reviews a gas company's supply planning process and the two major aspects of every utility's supply plan -- adequacy and cost.[21] 1990 Berkshire Decision (Phase 1), 19 DOMSC at 281; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 99; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71; Fall River Gas Company, 15 DOMSC 97, 111 (1986) ("1986 Fall River Decision"); 1986 Holyoke Decision, 15 DOMSC at 27; 1986 Berkshire Decision, 14 DOMSC at 128.

In its review of a gas company's supply plan, the Siting Council first reviews a company's overall supply planning process (see Section III.C, below). An appropriate supply planning process is essential to the development of an adequate, least-cost, and low-environmental impact resource plan. Pursuant to this standard, a gas company must establish that its supply planning process enables it to (1) identify and evaluate a full range of supply options and (2) compare all options -- including C&LM -- on an equal footing. 1990 Berkshire Decision (Phase 1), 19 DOMSC at 281; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 99; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC

21/ The Siting Council's enabling statute also directs it to balance cost considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. See Section III.C.3, below.

at 323; 1987 Berkshire Decision, 16 DOMSC at 85; 1986 Fall River Decision, 15 DOMSC at 115.[22]

The Siting Council next reviews a gas company's five-year supply plan to determine whether that plan is adequate to meet projected normal year, design year, design day, and cold-snap firm sendout requirements (see Section III.E, below).[23] In order to establish adequacy, a gas company must demonstrate that it has an identified set of resources which meet its projected sendout under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources which meet sendout requirements under a reasonable range of contingencies, the company must then demonstrate that it has an action plan which meets projected sendout in the event that the identified resources will not be available when expected. 1990 Boston Gas Decision, 19 DOMSC at 385; 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282; 1989 Bay State Decision, 19 DOMSC at 180; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 108; 1987 Bay State Decision, 16 DOMSC at 308; 1987 Berkshire Decision, 16 DOMSC at 71.

22/ In 1986, G.L. c. 164, sec. 69J was amended to require a utility company to demonstrate that its long-range forecast "include[s] an adequate consideration of conservation and load management." Initially, the Siting Council reviewed gas C&LM efforts in terms of cost minimization issues. In the 1988 ComGas Decision, 17 DOMSC at 122-126, the Siting Council expanded its review to require a gas company to demonstrate that it has reasonably considered C&LM programs as resource options to help ensure that it has adequate supplies to meet projected sendout requirements.

23/ The Siting Council's review of reliability, another necessary element of a gas company's supply plan, is included within the Siting Council's consideration of adequacy. See: Boston Gas Decision, 19 DOMSC 332, 385 n.25 (1990) ("1990 Boston Gas Decision"); 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282 n.16; 1989 Bay State Decision, 19 DOMSC at 180 n.19; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; 1987 Boston Gas Decision, 16 DOMSC at 214.

Finally, the Siting Council reviews whether a gas company's five-year supply plan minimizes cost (see Section III.F, below). A least-cost supply plan is one that minimizes costs subject to trade-offs with adequacy and environmental impact. 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282; 1989 Bay State Decision, 19 DOMSC at 180; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; See: Massachusetts Electric Company, 18 DOMSC 295, 337 ("1989 MECo Decision"). Here, a gas company must establish that application of its supply planning process has resulted in the addition of resource options that contribute to a least-cost plan.

B. Previous Supply Plan Review

In the 1986 Colonial Decision, the Siting Council approved Colonial's supply plan. However, in that Decision (14 DOMSC at 292), the Siting Council required the Company to comply with five Orders, three of which pertain to the supply plan:

> 2. That the Lowell Division discuss the status of the Tennessee MDQ/AVL project as far as delivery to the Company is concerned and, if significant delays are anticipated, discuss in detail the Division's plans for meeting firm requirements.
>
> 3. That if the Cape Division plans to sendout higher cost supplemental resources and not take lower cost pipeline resources, the Cape demonstrate how its proposed resource mix ensures that its firm customer's requirements are met at the lowest possible cost
>
> 4. That if the Lowell Division plans to rely on spot LNG purchases to meet its customer requirements Lowell demonstrate that a viable spot market for LNG exists.

In addition, as Order Five of the previous decision, the Siting Council directed Colonial to comply with its decision in the 1986 Gas Generic Order.

Order Two reflected Siting Council concerns regarding Colonial's reliance on the supplies that were constrained by Tennessee's pipeline capacity (14 DOMSC at 275, 288). The Company stated that it currently receives supplies from Tennessee in excess of the quantities of the resources related to the order.[24] As a result, the Siting Council's concerns relative to the Company's reliance on supplies constrained by Tennessee's pipeline capacity as reflected in Order Two have been resolved. Therefore, the Siting Council finds that the Company has complied with Order Two.

Order Three required Colonial to demonstrate that, if the Company makes certain dispatch choices, it would be able to ensure a least-cost, reliable supply for firm customers. Colonial indicated that it will not sendout higher cost supplemental resources instead of taking lower cost pipeline resources (Exh. HO-S-21). Therefore, the Siting Council finds that the Company has complied with Order Three.

With respect to Order Four, Colonial stated that it no longer includes plans to rely on spot LNG purchases in its supply plan to meet customer requirements (Exh. HO-S-15). Therefore, the Siting Council finds that the Company has complied with Order Four. Colonial's response to Order Five is discussed in Section III.C.2, III.E.3, III.F.2, and III.F.3, below.

C. Supply Planning Process

1. Standard of Review

The Siting Council has determined that an appropriate supply planning process is critical in enabling a utility company to formulate a resource plan that achieves an adequate, least-cost and low environmental impact supply for its

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24/ The Company's Tennessee supplies are transported through several pipeline expansion projects. Since the previous Colonial decision, Tennessee has completed subsequent expansion projects (see, e.g., Exh. HO-1A, p. 6).

customers. 1990 Berkshire Decision (Phase I), 19 DOMSC at 283; 1989 Bay State Decision, 19 DOMSC at 182; 1989 Fitchburg Decision, 19 DOMSC at 126-127; 1989 MECo Decision, 18 DOMSC at 336-338, 348-370; Boston Edison Company, 18 DOMSC 201, 224-226, 250-281 (1989); Eastern Edison Company, 18 DOMSC 73, 100-103, 111-131 (1988); 1987 Boston Gas Decision, 16 DOMSC at 247-248. The Siting Council has noted that an appropriate supply planning process provides a gas company with an organized method of analyzing options, making decisions, and reevaluating decisions in light of changed circumstances. 1987 Bay State Decision, 16 DOMSC at 332. For the Siting Council to determine that a gas company's supply planning process is appropriate, the process must be fully documented. 1987 Bay State Decision, 16 DOMSC at 332; 1987 Boston Gas Decision, 16 DOMSC at 247, 249; 1987 Berkshire Gas Decision, 16 DOMSC at 84.

The Siting Council's review of a gas company's supply planning process has focussed primarily on whether (1) the process allows companies to adequately consider C&LM options and (2) the process treats all resource options -- including C&LM options -- on an equal footing. 1990 Berkshire Decision (Phase I), 19 DOMSC at 283; 1989 Bay State Decision, 19 DOMSC at 179; 1989 Fitchburg Decision, 19 DOMSC at 123-124; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 323; 1987 Boston Gas Decision, 16 DOMSC at 252; 1987 Berkshire Decision, 16 DOMSC at 85; 1986 Fall River Decision, 15 DOMSC at 115.

In the 1989 Fitchburg Decision, the Siting Council clarified its standard for reviewing a company's supply planning process, noting that our review of a gas company's supply planning process, like our review of an electric company's supply planning process, must include an analysis of the company's documented process for identifying and evaluating resource options (19 DOMSC at 126-127).[25] Only through a comprehensive analysis of a company's process for identifying and evaluating resource options can the Siting Council determine specifically whether: (1) the process allows for the adequate consideration of C&LM; (2) the process treats all options on an equal footing; and (3) the process as a whole enables the company to achieve an adequate, least-cost, and low-environmental impact supply plan.

In the 1989 Bay State Decision, the Siting Council further clarified its standard for reviewing a gas company's process for identifying and evaluating resources, noting that the Siting Council considers whether the company: (1) has a process for compiling a comprehensive array of resource options -- including pipeline supplies, supplemental supplies, conservation, load management, and other resources; (2) has established appropriate criteria for screening and comparing resources within a particular supply category; and (3) has a mechanism in place for comparing all resources on an equal footing, i.e., across resource categories (19 DOMSC at 183).[26]

The Siting Council recognizes that fewer resource options may exist for gas companies than for electric companies and consequently that the resource identification and evaluation process may be considerably less complex for gas companies than for electric companies. However, the Siting Council concludes that the general framework for reviewing the supply planning

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25/ Although this standard of review was clarified in the 1989 Fitchburg Decision, this same standard historically has been used by the Siting Council in its supply plan reviews (see, e.g., 1986 Gas Generic Order, 14 DOMSC at 100-102). Additionally, in the 1986 Colonial Decision the Siting Council noted that it "will review each company's basis for selecting a supply alternative or the company's decision making process to ensure that the company's decisions result in supply options which are consistent with the Siting Council's mandate" (14 DOMSC at 271).

26/ The Siting Council's review of whether the application of the Company's planning process has resulted in a least-cost plan is addressed in Section III.F, below.

process identified above is applicable to gas companies. We also recognize that each gas company will have different supply planning options and needs and that each company's supply planning process will be different in some respects.

While the Siting Council acknowledges that the organization of our review in this case differs somewhat from our previous reviews of the Company's filings, this reorganization does not establish new regulatory standards nor place additional burdens on the Company.[27] Rather, our intent is to better track the manner in which gas company resource decisions are actually made, and to underscore our emphasis on the importance of the planning process as a foundation for the implementation of a least-cost supply plan.

2. Identification and Evaluation of Resource Options

The Company stated that its supply planning process emphasizes diversification of supply sources, flexibility of delivery to its separate divisions, and satisfaction of the operational needs of the Company's distribution system (Tr. 2, pp. 63, 93). The Company stated that in its effort to obtain economical gas supplies in accordance with these goals, Colonial is constantly alert to possibilities for bringing gas supplies to its customers (Exh. HO-S-2).

a. Existing Supplies

The Company identified its existing resources, including

27/ Prior to the 1989 Bay State Decision, the Siting Council, in essence, reviewed the above listed criteria in its evaluation of the adequacy of supply and in its evaluation of least-cost supply. See, e.g., 1989 Fitchburg Decision, 19 DOMSC at 102-127; 1987 Bay State Decision, 16 DOMSC at 313-325.

pipeline supplies and supplemental supplies.[28] The Company indicated that it reevaluates its usage of propane essentially whenever additional supplemental supplies are evaluated. The Company stated that it does not enter long-term contracts for propane, and instead relies on the spot market for propane supplies (Exh. HO-S-24). Accordingly, the Company seeks to displace propane in its supply mix with less expensive supplies (id.). The Company stated that it reevaluated a portion of its Tennessee CD-6 supply contract before converting that portion of the contract to firm transportation of third party supplies (Exh. HO-2). See Section III.C.2.b.i, below, for a discussion of the Sonat transportation agreements.

Although Colonial provided these examples of its reevaluation process, it is unclear from the record the extent to which the Company routinely evaluates its existing supplies. The Siting Council recognizes that, to the extent existing supply contracts can be renegotiated or existing supplies are purchased at the Company's option, periodic reevaluation of existing sources of supply is significant in enabling a company to make least-cost supply planning decisions. See 1990 Berkshire Decision (Phase I), 19 DOMSC at 287. In future filings, the Siting Council expects the Company to clearly document the reevaluation of existing supplies in its supply planning process.

b. Additional Supplies

The Company must identify and evaluate new sources of supply both to replace existing supplies and meet future demand. The Company provided a list of the considerations it used when evaluating the resource additions which are included

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28/ Colonial included pipeline supplies dependent upon the completion of the Champlain pipeline project in its tables of existing supply agreements (Exh. HO-1A, p. C-41). Colonial has reevaluated this supply to the extent of reconsidering the likely date these supplies will be available (Exh. HO-1B, p. 7). The Siting Council recognizes that the Champlain supplies are not expected to be available within the forecast period, and, therefore, does not include them in its analysis.

in its current supply plan (Exh. HO-S-17).[29] The Siting Council reviews the Company's process for identifying and evaluating resource additions within three categories: pipeline supplies; supplemental supplies; and conservation and load management.[30] The Siting Council also reviews the Company's process for evaluating additional supplies across resource categories.

i. Pipeline Supplies

Mr. Harrington stated that Colonial looks at long-term firm pipeline contracts to satisfy firm customer requirements and growth requirements (Tr. 2, p. 106). Mr. Harrington stated that, generally, "firm pipeline gas is your best source of gas to build your load with" (id., p. 98). Mr. Harrington explained that Colonial may make acquisitions that overlap with earlier contracts and create a surplus of supply, or that displace higher cost gas (id., pp. 55, 64). Mr. Harrington explained that expansion of pipeline capacity is not a frequent occurrence, and that the Company subscribes for quantities not knowing when an opportunity to obtain pipeline gas will recur (id., p. 64).

The Company stated that it identifies new pipeline supply options through its on-going activities in the industry (Exh. HO-S-2). The Company described its participation, at the Federal Energy Regulatory Commission ("FERC") and at seminars,

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29/ The Company listed the following criteria for the evaluation of new supplies: need, reliability, cost, flexibility, contract term, availability date, supplier's stability, supplier's ability to perform, purchase terms and conditions, volume available, perceived opportunity for revising volumes, quality of supply, security, options available, and alternatives (Exh. HO-S-17).

30/ Colonial includes fuel-sharing agreements under the heading of load management in its 1989 Forecast (Exh. HO-1A, p. 8, see also Exh. HO-RR-6). However, for the purposes of this review, the Siting Council addresses these agreements as a form of supplemental supplies.

and its consultation, with other local distribution companies and the Northeast Gas Markets group, as its primary information-gathering efforts (id.). The Company also maintains communications with the two interstate pipeline companies, Tennessee and Algonquin, and other potential suppliers that desire to provide pipeline gas supplies (id.). Colonial further stated that pipeline spot purchases are made after a monthly review of numerous bids from potential suppliers and consideration of need and operating constraints (Tr. 2, p. 119).

The Company identified several planned additions to its pipeline supplies during the forecast period: (1) a 40 percent expansion of its Tennessee CD-6 service as part of the Northeast Expansion Project ("NOREX"); (2) a supply from Alberta Northeast ("ANE") to be delivered via the Iroquois Gas Transmission System ("Iroquois"); and (3) a winter supply from Sonat Marketing Company ("Sonat"), to be delivered via a conversion of Tennessee pipeline capacity formerly used for a portion of Colonial's Tennessee CD-6 gas supply (Exhs. HO-1A, pp. C-39, L-36, HO-1B, pp. 10-11, HO-S-18).

The Company indicated that the evaluation of the NOREX option was limited to the Company's consideration of its desire for additional pipeline supply, the lack of alternatives, and the longstanding relationship between the Company and Tennessee (Exh. CGC-8; Tr. 2, p. 98). The Company's description of its identification and evaluation of the ANE volumes consisted only of the following statement: "Iroquois was another of the three surviving discrete open season projects ... While this project did not offer as many advantages to Colonial as the Champlain project, it was a potential source of new long-term pipeline supply which would help the Lowell division meet its growth requirements" (Exh. CGC-7). The Company's witnesses were unaware of any additional evaluation of this purchase (see Tr. 2, pp. 89, 91, 95).

The Company stated that its acquisition of gas from Sonat is the result of very recent planning decisions (Exh. HO-2). The Company stated that it pursued fuel-sharing agreements with each of the cogeneration projects under development in its territory, but found that such arrangements would be available only after the construction of new pipeline(s) (Exh. HO-1A, pp. 8-9). (See Section III.C.2.b.ii, below, for a discussion of fuel-sharing agreements.) Colonial indicated that discussions with one cogeneration developer, L'Energia, however, led to the Company's identification of a potential transportation-sharing agreement (id., Exh. HO-2, p. 3).

The Company explained that L'Energia has contracted with Sonat to purchase L'Energia's total daily requirement of 17,300 MMBtu for the months April through October (Exh. HO-2, p. 3). Colonial indicated that by converting a portion of its CD-6 capacity on the Tennessee system to firm transportation, it would be able to deliver the Sonat volumes to the L'Energia plant for those seven months (id., p. 10), and would have the opportunity to replace those CD-6 volume with an alternative source (id., p. 9).[31] The Company stated that it sought an alternative supply that was less expensive and equally as secure as the Tennessee volumes that would be replaced (id.).

Colonial stated that its offer of a portion of its existing firm transportation rights to L'Energia during the non-heating season required Colonial to select a gas supplier that could use the two receipt points previously selected by L'Energia (id., p. 10).[32] Colonial sought a supplier with recourse to call upon affiliates that also had the ability to deliver to the two receipt points as a reliability measure (id.). Colonial stated that Sonat and two other potential

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31/ The Company noted that in order to pursue this transportation-sharing agreement with L'Energia it would be required to obtain an alternative supply because it does not have a contract option to convert sales capacity to transportation capacity for only part of the year (Exh. HO-2, p. 9).

32/ The Company explained that L'Energia chose Sonat and two specific receipt points for the Sonat volumes prior to Colonial's selection of a gas supplier (Exh. HO-2, pp. 9-10).

suppliers satisfied these reliability criteria, and that Sonat, as the supplier to L'Energia for seven months of the year, was in a superior position to satisfy the load of Colonial for the remaining five months of the year (id., p. 10). On the basis of the above mentioned reliability criteria, the financial strength of Sonat, and Sonat's underlying gas resources, the Company stated that it did not contact other known potential suppliers to evaluate the cost and reliability of their offers (id., pp. 10-11).

The Siting Council notes that the pipeline supply options available to gas companies are limited by transportation availability. The Company's process for identifying pipeline supply options is appropriate for a medium-sized company considering this limitation. However, as transportation possibilities increase through the conversion of pipeline sales service to transportation service, as in the Sonat and L'Energia arrangement, the Company will benefit from a more thorough and systematic approach to its identification of pipeline supply options.

The Siting Council finds that the Company's process for identifying pipeline supply options is appropriate. Further, the criteria which the Company listed for its evaluation of pipeline supply options are appropriate. However, the Company has not demonstrated that these criteria have been integrated into the Company's evaluation of pipeline supply options. The Siting Council notes that a mere listing of appropriate considerations is not a substitute for the consistent application of well-defined criteria in a systematic process. While the Company's evaluation of the Sonat volumes was based on some of its criteria -- such as reliability of supply and flexibility -- its evaluations of other options were not demonstrated to have been made in relation to any of the criteria. Thus the Company has failed to establish that it consistently evaluated its pipeline supply options based on its stated criteria. In addition, the Siting Council noted in its past review of Colonial's supply plan that "analysis of any gas supply project should include an evaluation of the optimal level of participation." 1986 Colonial Decision, 14 DOMSC at 273. Yet, the Company provided no evidence to indicate that it had done so for the pipeline options it pursued.

Accordingly, the Siting Council finds that the Company has not demonstrated that its process for evaluating pipeline supply options is reviewable or appropriate. The Siting Council, therefore, ORDERS Colonial, in its next forecast filing, to develop a comprehensive evaluation process based on specific written criteria that it will employ in the evaluation of all pipeline supply options, and to provide a complete description of how these criteria were applied to each pipeline supply option identified and evaluated by the Company.

ii. Supplemental Gas Supplies

The Company stated that the supplemental supplies available to it include underground storage, sharing with another end-user -- on-system or off-system, liquefaction of gas, purchase of LNG and purchase of propane. The Company indicated that the same activities that enable it to identify pipeline supplies constitute its process for identification of supplemental supplies (Exh. HO-S-17) (see Section III.C.2.b.i, above). The Company asserted that it uses the same criteria to evaluate supplemental gas options as are used for pipeline options, but with shifts in their weighting (id.).

The Company identified six planned or recently initiated additions to its supplemental supplies: (1) revisions to two contracts for LNG from Bay State Gas Company ("Bay State"), one effective from 1987 through 1996 for liquefaction during the summers, the other effective from 1987 through 1991-1992 for winter supply service (Exh. HO-S-18); (2) two separate five-year contracts for LNG from Distrigas, one which is effective from 1989 through 1994, and the other which is effective from 1990 through 1995 (Exh. HO-1B, pp. 7-8); (3) a long term underground storage and transportation service arrangement provided by CNG Transmission Corporation and Algonquin ("PSS-T service") (id.;

Tr. 2, p. 76); (4) an additional volume of PSS-T service (Exh. HO-1B, Table G-24-Cape; Tr. 2, pp. 79-80); (5) a fuel-sharing agreement with the Pepperell Power Associates' cogeneration plant ("Pepperell"), entitling Colonial to use Pepperell's gas supply during 10 days in the winter (Exh. HO-1B, pp. 9-10, Table G-24-Lowell); and (6) a second fuel-sharing agreement with the Consolidated Power Cogeneration plant in Lowell ("Lowell Cogeneration") which is expected to provide 6,500 MMBtu of peak-shaving gas beginning in 1991 (id., p. 10; Exh. HO-S-25).

The Company described its acquisition of the Bay State LNG in the context of its goals for supplemental supplies. Specifically, the Company stated that it "determined the best means of obtaining LNG for summer inventory refill is through a combination ... [of sources]" but the Company gave no explanation of the basis for this determination (Exh. HO-S-18). In its description of its evaluation, the Company listed three sources of LNG supplies that could fill the identified need (id., Exh. CGC-8). The Company indicated only that the Bay State LNG was less costly than propane but not the other LNG options (id.). The Company stated that the primary factor in its decisions to acquire the Bay State LNG contracts was reliability (Exh. HO-S-18). The Company noted that the Bay State LNG is "absolutely firm and available for a long term" (id.). The Company also indicated that projections of need were important to its decision (Exh. HO-S-24). Finally, the Company stated, but did not document, that the LNG options were evaluated utilizing the supply planning criteria (see Section III.C.2, n.29), The Company did not explain how it evaluated the desired or optimal level of purchase of this supply (id., Exh. HO-S-18).

The Company's evaluation of the two Distrigas LNG contracts focussed on reliability and flexibility (Exh. CGC-8). The Company stated that a reliable source of LNG for the Cape Division was needed and that these contracts could meet this need (id.). The Company stated that the contracts also provide the flexibility of delivery to the Lowell Division on a best efforts basis, either as liquid or as gas (id.; Tr. 2, p. 59). The Company was not able to identify any analysis indicating how the quantities of the two contracts were determined.[33]

The Company's evaluation of the two separate PSS-T purchases focussed on the criteria of reliability and diversity (Exh. HO-S-18; Tr. 2, pp. 78-79). However, when questioned about any evaluation to determine the optimal quantity of these purchases, the Company stated only that it purchased "the full amount offered to it" (Tr. 2, p. 79).

The Company did not indicate what criteria were used to evaluate its two fuel-sharing agreements or how the contracted quantities were evaluated and selected (see Exhs. HO-S-18, CGC-7, CGC-8). The Company explained that the fuel-sharing agreements rely on the cogenerators obtaining firm winter gas transportation (Tr. 2, p. 41). The Company noted that these agreements would not be considered reliable at present, nor were they at the time of the Company's decision to execute the agreements (id., pp. 41, 102). No other criteria were discussed in relation to the analyses of these two agreements.

The Siting Council notes, as it did for pipeline supply options, that the range of supplemental supply options available to gas companies is limited. The Company's process for identifying supplemental supplies, however, enables the Company to overcome this limitation to some degree as evidenced by the Company's identification of options such as the fuel-sharing

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33/ The Company asserted that the Distrigas volumes were intended to replace the Champlain pipeline volumes in the near-term (Exh. HO-1B, p. 7; Tr. 2, p. 59). However, the Company could not describe how the quantity of Champlain gas supply had been evaluated and selected, nor could it describe the status of the Champlain project at the time the first Distrigas quantity was acquired (Tr. 2, pp. 45-47, 49, 56). The Siting Council notes that the Distrigas contracts supply 10,000 MMBtu per day (Exh. HO-1B, Table G-24-Cape), but the Champlain volumes provide a total of 12,000 MMBtu per day (Exh. HO-1A, pp. C-39, L-49).

agreements with cogenerators. Therefore, the Siting Council finds that Colonial's process for identifying supplemental supply options is appropriate for a medium-sized gas company.

Further, the Company's stated criteria for evaluating supplemental options are generally appropriate.[34] However, the Company has not demonstrated that it consistently applies such criteria, including its criteria of need, volume available, cost and alternatives, in its evaluation of supplemental supply options. The Siting Council notes that Colonial identified some criteria used in evaluating its supplemental supply options. However, the record fails to establish that Colonial applied all of its relevant criteria in its evaluation process. As noted above in Section III.C.2.b.i, listing appropriate considerations is not a substitute for the consistent application of well defined criteria or an evaluation of the optimal level of quantity for each supply addition. Colonial has failed to establish that it has performed either of these evaluations in its analysis of its six supplemental supply decisions.

Accordingly, the Siting Council finds that the Company has not demonstrated that its process for evaluating supplemental supply options is reviewable or appropriate. The Siting Council, therefore, ORDERS Colonial, in its next filing, to develop a comprehensive evaluation process based on specific written criteria that it will employ in the evaluation of all supplemental supply options, and to provide a complete

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34/ The Siting Council notes that the Company indicated that the relative weights applied to its criteria varied depending on whether pipeline or supplemental supplies were being evaluated. However, the Company did not explain which criteria were weighed more heavily in each of these processes. The Siting Council concedes that different weights for the same criteria may well be appropriate depending on the type of supply being considered. However, due to the Company's lack of further explanation on this point, the Siting Council is unable to determine if the Company, in fact, appropriately weighed its various criteria in its evaluation of both pipeline and supplemental supplies.

description of how these criteria were applied to each supplemental supply option identified and evaluated by the Company.

c. Conservation and Load Management

i. Conservation

The process by which Colonial identifies and evaluates conservation resources has evolved significantly during the course of this proceeding. In 1990, the Company submitted to the Massachusetts Department of Public Utilities ("MDPU") a request for preapproval of a pilot conservation program; this request was docketed as D.P.U. 90-90 (Exh. HO-1B, p. 4). The Company stated that it relied on an avoided cost study prepared by LaCapra Associates ("LaCapra study"), and a cost-benefit analysis prepared by Xenergy, Incorporated ("Xenergy analysis") in preparing its pilot conservation program (Exh. HO-S-20; Tr. 1, p. 132). Colonial stated that the proposed pilot program includes a weatherization program for fuel assistance customers and a low-interest loan program (Exh. HO-1B, Section VI, pp. 70-72).

In response to orders in D.P.U. 90-90, Colonial submitted a revised Xenergy analysis to the DPU, dropped measures which were found not to be cost-effective based on the revised analysis, offered its loan program without interest, and converted the pilot project into an accelerated effort ("ramp-up") leading to a full-scale conservation program (id., pp. 76-89). Colonial stated that this ramp-up program was offered to Colonial customers beginning in January, 1991 (Tr. 1, pp. 104-105).

On July 1, 1991, Colonial submitted to the MDPU a request for preapproval of its full-scale conservation program (Exh. HO-RR-4). The Company stated that it relied on an updated version of the LaCapra study, and a technical potential study prepared by Energy Investment, Incorporated ("EII study") in preparing the full-scale program (Tr. 1, p. 110).

The Company stated that it worked with Xenergy to identify and evaluate residential conservation measures to be included in the ramp-up program (id., p. 132). The Xenergy analysis estimated the costs and energy savings associated with a variety of conservation measures based on Xenergy's experience with conservation programs, and compared these costs and savings to the Company's avoided costs (id.). The Company stated that it did not consider any non-cost criteria when evaluating measures for inclusion in the ramp-up program (id., p. 133).

Colonial stated that it identified and evaluated conservation measures for its full-scale program using the EII study (id., p. 110). The Company indicated that the study evaluated all residential measures found in the MASS-SAVE Energy Conservation Service audit database, plus two additional residential measures developed by EII (Exh. HO-RR-4, Technical Potential Study, p. 42). The EII study also evaluated those commercial/industrial measures found in the MASS-SAVE XENCAP audit database (id.). The Company noted that most Massachusetts gas utilities rely on audit data to identify conservation measures to be considered for their full-scale conservation programs (Tr. 1, p. 111)

Colonial stated that its evaluation of conservation measures is based strictly on the MDPU's societal cost/benefit test (id., p. 112). The Company noted that it offers measures with a cost/benefit ratio greater than 1.0 as part of its programs; whereas measures with a cost/benefit ratio lower that 1.0 are not offered (id., p. 131). Measures which are cost-effective only in one territory, or only for a certain type of customer, are offered only where and to whom they are cost-effective (id., pp. 123-124). Colonial noted that the revised LaCapra study incorporates monetized environmental externalities (id., pp. 112-113). The Company, therefore, argued that a supply decision based on the societal cost-benefit test reflects environmental as well as cost considerations (id.).

The Siting Council recognizes that it is important for utilities to offer conservation measures which are cost-effective in their own service territories. Therefore, we agree that territory-specific audit data such as the MASS-SAVE data can be an appropriate starting point for the identification of potential conservation resources. However, the Siting Council notes that if utilities do not move beyond a list of measures for which they already have audit data, potentially cost-effective conservation resources not included in earlier audits will be overlooked.

The Siting Council notes that Colonial has taken an initial step in this direction. The Company has presented evidence that, in the EII study, two conservation measures not included in the MASS-SAVE audit database were identified and evaluated. At the MDPU's request, the Company also evaluated the cost-effectiveness of a rebate program for high-efficiency heating systems (id., pp. 153-154).[35] Therefore, for the purposes of this review, the Siting Council finds that the use of MASS-SAVE data, supplemented by the expertise of Colonial's consultants, is an appropriate process for identifying conservation resources.

The Siting Council notes that Colonial's process for evaluating conservation resources is among the most detailed and comprehensive processes that we have reviewed to date. The Company has presented an extensive societal cost/benefit study based on Colonial's own avoided costs and territory-specific savings data. Additionally, the EII study has provided the Company with information on the potential size of conservation resources available to it.

However, Colonial's process for evaluating conservation options needs to be further expanded. While it is appropriate for the Company to evaluate conservation options on the basis of

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35/ The Company concluded that uncertainty about the effect of forthcoming Annual Fuel Utilization Efficiencies ("AFUE") standards, the relationship between incremental cost and incremental efficiency, and potential free rider problems made it impossible to design a cost-effective program for high-efficiency heating systems (Exh. HO-RR-4, Scholten Testimony, p. 15).

an MDPU-approved societal cost/benefit test, the Company must ensure that its supply planning process for conservation does not neglect important non-price criteria. The Siting Council has recently placed specific emphasis on the need to incorporate non-price criteria into the decision to acquire conservation resources. 1990 Boston Gas Decision, 19 DOMSC at 401-402; 1990 Berkshire Decision (Phase I), 19 DOMSC at 295-296; 1989 Bay State Decision, 19 DOMSC at 190-191.

Here, Colonial has incorporated monetized environmental externalities into its cost-benefit calculations. This is a significant first step towards a process which incorporates non-price criteria into supply decisions. However, the Company has failed to take into account other non-cost criteria such as timing and reliability. These are precisely the criteria which the Company states that it uses to justify its acquisition of more traditional supply options (see Sections III.C.2.b.i & ii, above). The Siting Council sees no reason why the Company should not also use these criteria to evaluate its conservation options.

Colonial has described a process for identifying and evaluating conservation resources which incorporates cost and environmental factors in a comprehensive manner. Accordingly, the Siting Council finds that Colonial's supply planning process for conservation resources is an appropriate means of identifying and evaluating conservation options. However, the Siting Council remains concerned that the Company has not incorporated into this planning process additional non-cost factors, which were incorporated in the Company's evaluation of more traditional resources. The Siting Council, therefore, ORDERS Colonial in its next filing to identify specific non-price criteria which will be used to evaluate conservation resources, as well as describe how each of these non-price criteria was applied to each conservation resource identified and evaluated by the Company.

ii. Load Management

Colonial stated that, in addition to its conservation programs, it engages in a variety of load management activities, including the sale of interruptible gas and transportation services, strategic load-building in the form of new off-peak uses, and fuel-sharing agreements with large end-users.[36] However, the Company did not describe its process for identifying and evaluating load management opportunities (see Tr. 1, pp. 169-174; Exh. HO-RR-6). The Siting Council, therefore, makes no finding regarding Colonial's identification and evaluation of load management resources.

The Siting Council also has concerns regarding the role of interruptible sales in Colonial's load management planning. Mr. Griffin, Colonial's Director of Rates and Revenue Requirements, stated that his department seeks to devise firm rates which would attract current interruptible customers to switch to firm service (Tr. 1, pp. 170-172). Mr. Griffin also stated, however, that the Company recognizes the benefits of interruptible load, including sales of gas to large customers in the valley portion of the Company's supply year, and rate benefits to firm customers (id., 174-175). The Siting Council notes that the conversion of interruptible customers to firm service would deprive the Company of these benefits. It is possible that such conversions offer larger, off-setting benefits; however, the Company has not clearly identified the tradeoffs involved in its policy (see id., pp. 171-177).

36/ Colonial includes in its base case supply plan volumes of gas purchased from Pepperell and Lowell Cogeneration under fuel-sharing agreements (Exh. HO-1B, Table G-22N-Lowell, Table G-22D-Lowell). As noted earlier, the Siting Council categorizes these as supplemental gas supplies, and describes them in Section III.C.2.b, above. The Company also refers to its transportation agreement with L'Energia as a load management measure (Exh. HO-1A, pp. 8-10). The Siting Council addresses this agreement in Section III.C.2.a, above.

The Siting Council believes that Colonial needs to provide a clearer explanation of its load management activities, including its policies on interruptible customers. Accordingly, the Siting Council ORDERS Colonial to include in its next filing an explicit discussion of how it identifies and evaluates load management options, including a stated rationale or policy on the conversion of interruptible customers to firm service.

d. Consideration of All Resources on an Equal Footing

The Siting Council consistently has held that in order for a gas company's supply planning process to minimize cost, that process must adequately consider alternative resource additions, including C&LM options, on an equal basis. 1990 Boston Gas Decision, 19 DOMSC at 402; 1990 Berkshire Decision (Phase I), 19 DOMSC at 296; 1989 Bay State Decision, 19 DOMSC at 195; 1989 Fitchburg Decision, 19 DOMSC at 123; 1988 ComGas Decision, 17 DOMSC at 138-139; 1987 Bay State Decision, 16 DOMSC at 319; 1987 Boston Gas Decision, 16 DOMSC at 252; 1987 Berkshire Decision, 16 DOMSC at 85; 1986 Fall River Decision, 15 DOMSC at 115.

Colonial has developed a strong process for identification and evaluation of conservation resources. Its societal cost/benefit analysis compares each conservation resource to the avoided traditional resource on an equal footing with regard to two criteria: cost and environmental externalities. This analysis represents a significant advance toward a true least-cost planning process. However, Colonial's societal cost/benefit analysis, as currently implemented, does not evaluate non-price criteria such as flexibility, reliability and timing, even though the Company asserts that it relies heavily on such criteria in its evaluation of traditional supply options.

Colonial's planning process for pipeline and supplemental supply resources is substantially less sophisticated. The Company has not demonstrated that its supply planning process ensures that it will compare a reasonable range of supply options at the times when resource decisions are made. On the contrary, recent supply decisions are the result of case-by-case applications of criteria such as reliability, diversity, and flexibility (see Sections III.C.2.a & b, above). In addition, the Company's application of its criteria is inconsistent. Without a comparison of a reasonable range of supply options, the Company cannot establish that it is truly treating all resource options on an equal footing. Further, the Company has given no consideration to the optimal size of any pipeline or supplemental resource acquisition, although it conducted considerable analysis to ensure that it acquired an optimal quantity of conservation resources.

The Siting Council notes that the Company has created an interdepartmental integrated resource management group to formalize the process of providing safe, reliable service at the least possible cost (Tr. 1, pp. 160-163). The Siting Council urges this group to build on the work of the conservation program to create a truly integrated supply acquisition process which includes the comparison of a reasonable range of alternatives at the time of each supply decision, and which incorporates the systematic evaluation of non-price criteria for all resource options.[37]

Based on the above, the Siting Council finds that the Company has failed to establish that its supply planning process ensures the treatment of all supply options on an equal footing.

37/ In Sections III.C.2.a & b, above, the Siting Council has ordered Colonial to develop specific written criteria that it will follow in the evaluation of all pipeline and supplemental supply options, and to describe how these criteria are applied to each such supply option identified and evaluated by the Company. The Siting Council expects that the specific criteria developed in response to these orders will ensure that resource options will be evaluated on an equal footing.

3. Conclusions on the Supply Planning Process

In the 1986 Gas Generic Order, the Siting Council notified all gas companies that, as a result of dramatic changes in the natural gas industry, the Siting Council and the gas companies must take into consideration additional criteria beyond reliability when evaluating supply additions (14 DOMSC at 100, 101). In the 1986 Colonial Decision, the Siting Council expressed concern regarding Colonial's lack of analyses in the determination of what level of participation would be optimal for new supply options (14 DOMSC at 273).

In this proceeding, the Siting Council found that Colonial's processes for identifying pipeline supply options, supplemental supply options and conservation options and for evaluating conservation options are appropriate. The Siting Council found that Colonial's process for evaluating pipeline supply options and supplemental supply options are not reviewable or appropriate for making decisions among such options. Further, the Siting Council made no finding regarding Colonial's identification and evaluation of load management resources. Finally, the Siting Council found that Colonial failed to establish that its supply planning process ensures the treatment of all supply options on an equal footing.

The Siting Council notes that in many instances, the Company was unable to describe critical aspects of the supply planning process that are under review in this proceeding. We are particularly concerned that this inability has persisted even after the Siting Council stated in the 1986 Colonial Decision that optimal levels of participation should be analyzed for any gas supply project and that the Siting Council comprehensively would review the Company's supply planning process (14 DOMSC at 271, 273). The Siting Council has repeatedly emphasized the importance of the planning process with respect to gas companies' resource decisions. 1990 Boston Gas Decision, 19 DOMSC at 388-390; 1990 Berkshire Decision (Phase I), 19 DOMSC at 283-285; 1989 Bay State Decision, 19 DOMSC at 182-183; 1989 Fitchburg Decision, 19 DOMSC at 126-127; 1987 Berkshire Decision, 16 DOMSC at 71-72.

The Siting Council acknowledges that Colonial's use of a thorough and rigorous process for identifying conservation resources represents a significant improvement by the Company since the previous review. The Company, however, has not adopted two specific improvements to its evaluation of supply options that the Siting Council instructed the Company to make in the previous decision and in the 1986 Gas Generic Order. In our opinion, the increased number of options available to gas companies, and, consequently, the increased complexity of the decisions which must be made, require thorough, well documented evaluations of the bases for such decisions. The lack of such documented evaluations here effectively prevents the Siting Council from reviewing the Company's supply planning process. Accordingly, the Siting Council makes no finding as to whether the Company's supply planning process enables it to make least-cost supply decisions.

The Siting Council's enabling statute also directs it to balance economic considerations with environmental impacts in ensuring that the Commonwealth has a necessary supply of energy. G.L. c. 164, sec. 69H. In the future, the Siting Council directs Colonial to include in their supply planning process an adequate consideration of the environmental impacts of resource options.

D. Base Case Supply Plan

In this section the Siting Council reviews the Company's supply plan and identifies elements which represent potential contingencies affecting adequacy of supply or which potentially impact the cost of the supply plan. The Siting Council then reviews the adequacy of the Company's supply plan in Section III.E, below, and the cost of the Company's supply plan in Section III.F, below.

1. Pipeline and Supplemental Gas Supplies

Colonial indicated that its Cape Division receives pipeline gas and storage return gas from Algonquin (Exh. HO-1A, pp. 1, C-37, C-46 through C-49). Algonquin delivers firm gas under rates F-1, F-2, F-3, F-4 and WS-1 (id., p. C-40). The Company also indicated that Algonquin has filed a service restructuring program before FERC, which would not change Colonial's volumes (Exhs. HO-1B, p. 6, HO-CS-3).

Algonquin also provides the Cape Division with storage service and return transportation under rates STB, SSIII, and PSS-T (Exh. HO-1A, pp. C-38, C-40, C-43). Under rate STB, Algonquin provides firm return transportation throughout the year and interruptible transportation (id.). Colonial also receives gas storage service from Algonquin under rate SS-II (id., p. C-40). The Company has contracted with CNG Transmission Corporation for additional firm underground storage capacity beginning in November, 1989 (id., p. C-38). This capacity will increase incrementally in November, 1991 and November, 1992 (Exh. HO-1B, Table G-24-Cape). Firm transportation of these volumes would be provided by Algonquin under the PSS-T rate, and by Texas Eastern Transmission under the FTS-5 rate (id.). (These capacity increases are discussed as a contingency in Section III.E, below.) Colonial also makes use of Algonquin interruptible transportation provided under Section 311 of FERC regulations for the movement of spot purchases (Exh. HO-1A, p. C-37).

Algonquin provides the Cape Division with LNG and LNG storage service on a best efforts basis under rate T-LG (id., p. C-40). The Company indicated that LNG storage facilities are located in South Yarmouth, Wareham, and Providence, Rhode Island (id.). The Company indicated that LNG is provided from the Providence facility under a contract with Algonquin LNG which expires in 1992 (id.). The Company indicated that this contract will be extended for two additional years (Tr. 2, p. 72). Bay State provides LNG under three contracts, with flexibility to deliver to both the Cape and Lowell Divisions (Exhs. HO-1A, p. C-41, HO-1B, Table G-24-Cape).

Colonial indicated that its Lowell Division receives pipeline gas and storage return gas from Tennessee (Exh. HO-1A, pp. 1, L-36, L-43 through L-46). Colonial indicated that Tennessee provides firm gas under its CD-6 rate (id., p. L-37). Colonial indicated that it has increased its CD-6 volumes as part of Tennessee's NOREX project (id., p. L-36). The Company stated that it received 52 percent of its contracted NOREX volumes in the winter of 1989-1990 and its full NOREX volumes beginning November 15, 1990 (id., p. 6, Exh. HO-1B, p. 9). Colonial also indicated that it intends to convert approximately one-third of its CD-6 gas supply to firm transportation as part of what the Company describes as a load-management agreement with L'Energia (Exh. HO-1B, pp. 10-11) (see Section III.C.2.b, above). Tennessee also provides transportation for storage return gas from the Penn-York Energy Corporation on a firm basis under rate SST-NE, and on a best efforts basis under rate ISST-NE (Exh. HO-1A, p. L-36).

Colonial also indicated that it has a new pipeline gas contract and a new commodity contract to supply the Lowell Division with 2,000 MMBtu per day from ANE to be delivered on a firm basis via the Iroquois pipeline beginning in November, 1991 (Exh. HO-1B, p. 9, Table G-24-Cape). (This supply is discussed as a contingency in Section III.E, below.) In addition, the Company indicated that it has entered into two long-term contracts with Sonat for a winter season gas supply to be delivered on a firm basis by Tennessee (id., p. 10, Table G-24-Lowell) (see Section III.C.2.b, above).

With respect to supplemental supplies, Distrigas provides the Lowell Division with LNG on a best efforts basis, with flexibility to deliver to both the Lowell and Cape Divisions (Exhs. HO-1A, p. L-37, HO-S-18). Colonial stated that the Distrigas LNG can be delivered in vapor or liquid form (Exh. HO-1A, pp. L-36, L-37).

Finally, the Lowell Division base case supply plan includes two fuel-sharing agreements with Pepperell and Lowell Cogeneration that provide peak-shaving gas diverted from either cogenerator when it is capable of burning its alternate fuel (id., p. 9). Colonial stated that the fuel-sharing agreements require that the cogenerators have a firm winter gas supply (id.). However, Colonial stated that since both the Pepperell and Lowell Cogeneration projects were to receive firm gas through the Champlain pipeline, a pipeline that is currently delayed (id.), both plants are now in operation using alternate fuel arrangements (Exh. HO-1B, pp. 9-10). Colonial stated that it anticipates that each project will succeed in obtaining firm supply and be able to provide the supplemental gas to Colonial beginning in the 1991-1992 season (id.). (These two supplies are discussed as a contingency in Section III.E, below.)

2. Conservation

Colonial has offered two residential conservation programs -- a weatherization program for low-income customers and a zero-interest loan program -- since January, 1991 (Tr. 1, pp. 105-106). The Company stated that the low income program offers a variety of insulation measures free of charge to Colonial residential heating customers who receive fuel assistance (id., pp. 105, 135). The Company stated that the zero-interest loan program offers similar measures to Colonial's residential heating customers who have previously had a MASS-SAVE audit in which insulation measures were recommended (id., pp. 135-138). From the inception of the program through May, 1991, 104 customers have participated in the low-income program, and 12 customers have participated in the loan program (Exh. HO-RR-4, Gillette Testimony, p. 43). The Company notes that it intends to phase out these two "ramp-up" programs when its full-scale conservation programs are implemented (id., Stavropoulos Testimony, p. 13). The Company offered no estimate of the timing or quantity of savings expected to result from the two ramp-up programs.

Colonial stated that, subject to MDPU approval, it will offer its customers a full-scale conservation program, including a single-family and multi-family residential program and a commercial/industrial program (Tr. 1, p. 105). The Company stated that the residential program will offer different bundles of measures based on the type of customer (single-family or multi-family) and location (Lowell or Cape Division) (Exh. HO-RR-4, Stavropoulos Testimony, p. 13, Gillette Testimony, pp. 6-8). The Company stated that it will offer a 100 percent subsidy to low-income customers and renters, and a 50 percent subsidy to non-low-income homeowners (id., Stavropoulos Testimony, p. 15).

Colonial further stated that, as part of the full-scale program, small and medium-sized commercial and industrial customers will be offered a bundle of conservation measures which the Company has found to be cost-effective in commercial/industrial settings (id., p. 16). The Company stated that it will offer a 50 percent subsidy to its small and medium-sized commercial and industrial customers (id.).

Finally, Colonial indicated that large commercial and industrial customers will be offered a "custom" conservation program (id.). Colonial will pay 50 percent of the installed costs of conservation measures recommended for a specific customer by an energy audit or engineering study (id.).

Colonial estimated that conservation measures installed through the full-scale residential program over a 24 month period will result in annualized savings of 131,133 thousand cubic feet ("Mcf") (id., Griffin Testimony, pp. 3-4, 37). Similarly, the Company estimated that the commercial/industrial program will result in annualized savings of 115,263 Mcf after two years (id.).

These conservation resources do not appear in Colonial's base case supply plan. The Siting Council recognizes that it would have been impossible for Colonial to include the resources expected from full-scale conservation programs in the 1989 or 1990 forecast filings, since the details of the program were not settled until very recently. However, in future forecast filings, the Company must include projected conservation resources in its base case supply plan. The Siting Council discusses this matter as it relates to the cost of the Company's supply plan in Section III.F.2.g, below.

E. Adequacy of Supply

As stated in Section III.A, above, the Siting Council reviews the adequacy of a gas company's five-year supply plan. In reviewing adequacy, the Siting Council first examines whether the Company's base case resource plan is adequate to meet its projected normal year, design year, design day, and cold-snap firm sendout requirements. If so, the Siting Council reviews whether the Company's plan is adequate to meet its sendout requirements if certain supplies become unavailable. If the supply plan is not adequate under the base case resource plan or not adequate under the contingency of existing or new supplies becoming unavailable, then the company must establish that it has an action plan which will ensure that supplies will be obtained to meet its projected firm sendout requirements.

1. Normal Year and Design Year Adequacy

In normal and design year planning, Colonial must have adequate supplies to meet several types of requirements. Colonial's primary service obligation is to meet the requirements of its firm customers. In addition, the Company must ensure that its storage facilities have adequate inventory levels prior to the start of the heating season. To the extent possible, Colonial also supplies gas to its interruptible customers.

Although the Siting Council previously found that the Company's forecasts of normal year, design year, and design day sendout requirements are not reliable (see Section II, above), those forecasts serve as the only available bases for judging the Company's supply preparedness, and, therefore, the Siting Council will use them in its review of supply adequacy. 1988 ComGas Decision, 17 DOMSC at 110; 1987 Boston Gas Decision, 16 DOMSC at 239.

a. Base Case Analysis

Colonial presented its supply plans for meeting its forecasted normal and design year sendout requirements throughout the forecast period on a division-specific basis (Exh. HO-1A, pp. C-46, L-43). The Company's base case, normal year supply plans for both divisions demonstrate that the Company has adequate supplies to meet forecasted normal year requirements throughout the forecast period (Exh. HO-S-15). Accordingly, the Siting Council finds that Colonial has established that its base case, normal year supply plan is adequate to meet the Company's forecasted firm sendout requirements and storage refill requirements on a division-specific basis throughout the forecast period.

Additionally, the Company's base case, design year supply plans for both divisions demonstrate that Colonial would meet its forecasted design year requirements in all years of the forecast period (id.). Accordingly, the Siting Council finds that Colonial has established that its base case, design year supply plan is adequate to meet the Company's forecasted firm sendout requirements and storage refill requirements on a division-specific basis throughout the forecast period.

Colonial's forecasted design year firm sendout requirements and base case, design year supply plan for the heating season are summarized in Tables 2A and 2B.[38]

b. Contingency Analysis

The Company's base case supply plan includes supplies which are not yet in place and which require both permitting and construction activities outside the Company's control (see Sections III.D.1 and III.D.2, above). The Siting Council, therefore, reviews the adequacy of the Company's supply plan in the event that one of the following contingencies occurs: (i) an indefinite delay in the delivery of 302 BBtu of ANE supplies from the Iroquois project to the Lowell Division; (ii) termination of the fuel-sharing agreements for 165 BBtu for the Lowell Division; or (iii) termination of an agreement for storage and transportation by Algonquin of 232.6 BBtu per year to the Cape Division.

38/ As indicated in Section III.D.2, above, the Company's base case, design year and base case, design day supply plans do not include anticipated gas savings from conservation programs.

i. Indefinite Delay in Iroquois Project

Colonial's supply plan for the Lowell Division calls for an in-service date of November, 1991 for the Iroquois project and associated deliveries of the 302 BBtu from ANE during the heating season. In the event that delivery of these supplies is delayed indefinitely, and if all other resources remain available to the Company, the Company would not experience a resource deficiency during the forecast period (see Table 2A).

Accordingly, the Siting Council finds that the Company has adequate resources to meet forecasted firm design year sendout requirements and storage refill requirements in the event of an indefinite delay in the Iroquois project.

ii. Termination of Fuel-Sharing Agreements

As noted previously, the Company's Lowell Division supply plan calls for two supplemental supplies totalling 165 BBtu through fuel-sharing agreements with cogenerators, entering service in the heating season of 1991-1992. In the event that both of these agreements are terminated, and if all other resources remain available to the Company, the Company would not experience a resource deficiency during the forecast period (see Table 2A).

Accordingly, the Siting Council finds that the Company has adequate resources to meet forecasted firm design year sendout requirements and storage refill requirements in the event of termination of the fuel-sharing agreements.

iii. Termination of Storage and Transportation Agreement for 232.6 BBtu

As noted previously, the Company's Cape Division supply plan calls for supplemental supplies to be delivered through storage and firm transportation under the PSS-T service. In the event that the largest of these supply arrangements, for the storage and transportation of 232.6 BBtu per year entering service in November, 1992, is terminated, and if all other resources remain available to the Company, the Company would not experience a resource deficiency during the forecast period (see Table 2B).

Accordingly, the Siting Council finds that the Company has adequate resources to meet forecasted firm design year sendout requirements and storage refill requirements in the event of termination of the storage and transportation agreement for 232.6 BBtu per year.

2. Design Day Adequacy

Colonial must have an adequate supply capability to meet its firm customers' design day requirements. While the total supply capability necessary for meeting design year requirements is a function of the aggregate volumes of gas available over some contract period, design day supply capability is determined by the maximum daily deliveries of pipeline gas, the maximum rate at which supplemental fuels can be dispatched and the quantity of reliable C&LM available on a peak day.

a. Base Case Analysis

Colonial presented its base case, design day supply plan in support of its assertion that it has adequate resources to meet forecasted firm sendout requirements for each division (Exh. HO-1A, p. 1; Brief, p. 10). The Company's base case, design day supply plan includes volumes from the fuel-sharing agreements and the PSS-T storage and transportation service in addition to new pipeline supplies. These plans indicate that the Company has adequate resources to meet its forecasted firm design day sendout requirements on a division-specific basis throughout the forecast period.

Accordingly, the Siting Council finds that Colonial has established that its base case, design day supply plan is adequate.

b. Contingency Analysis

In the analysis of Colonial's normal and design year supply plan, the Siting Council reviewed the Company's adequacy in the event of various contingencies (see Section III.E.1.b, above). The Siting Council here reviews these same contingencies with reference to Colonial's design day supply plan. In the event of either: (i) an indefinite delay in the delivery of 2.0 BBtu per day of ANE supplies from the Iroquois project to the Lowell Division; (ii) termination of the fuel-sharing agreements with cogenerators for 15.6 BBtu per day for the Lowell Division; or (iii) termination of an agreement for delivery of 2.326 BBtu per day to the Cape Division the Company would not be subject to a design day resource deficiency in either of its divisions (See Tables 3A and 3B).

Accordingly, the Siting Council finds that the Company's base case, design day supply plan is adequate to meet forecasted firm sendout requirements in both divisions in the event of either: (i) an indefinite delay in the delivery of 2.0 BBtu per day of ANE supplies from the Iroquois project to the Lowell Division; (ii) termination of the fuel-sharing agreements with cogenerators for 15.6 BBtu per day for the Lowell Division; or (iii) termination of an agreement for delivery of 2.326 BBtu per day to the Cape Division.

3. Cold-Snap Adequacy

In the 1986 Colonial Decision, the Siting Council ordered Colonial to submit a cold-snap analysis or explain why such an analysis is unnecessary to demonstrate cold-snap preparedness as part of its Order Five requiring compliance with the 1986 Gas Generic Order (14 DOMSC at 291, 293). The Siting Council has defined a cold-snap as a prolonged series of days at or near design conditions. 1989 Bay State Decision, 19 DOMSC at 219; 1989 Fitchburg Decision, 19 DOMSC at 120; 1988 ComGas Decision, 17 DOMSC at 137.[39] A gas company must demonstrate that the

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39/ In the 1986 Gas Generic Order the Siting Council explained a cold-snap as "a protracted period of design or near-design weather" (14 DOMSC at 97).

aggregate resources available to it are adequate to meet this near maximum level of sendout over a sustained period of time, and that it has and can sustain the ability to deliver such resources to its customers. 1989 Bay State Decision, 19 DOMSC at 219; 1989 Fitchburg Decision, 19 DOMSC at 120; 1988 ComGas Decision, 17 DOMSC at 137; 1987 Bay State Decision, 16 DOMSC at 315-316; 1987 Berkshire Decision, 16 DOMSC at 79; 1986 Fitchburg Decision, 15 DOMSC at 58.

a. Description

In response to the Siting Council's order in the 1986 Colonial Decision, the Company presented a cold-snap analysis (Exh. CGC-1). The Company stated that it selected the actual thirty coldest day occurrence, as reported by the WSC from its weather data base of the past one hundred years, as the basis for the cold-snap analysis (Tr. 1, pp. 12-13, Tr. 2, p. 3). The identified thirty days occurred between December 15, 1980 and January 14, 1981 (Tr. 1, pp. 12-13; Exh. CGC-1). The Company then assumed that the cold-snap would occur in January because "January has the highest base-load and heat-load factors in our projections, which will give us the greatest amount of sendout" (Tr. 1, p. 12) thereby assuming a worst-case scenario, i.e., a cold-snap occurring when the Company would normally experience its greatest system demands.

The Company presented its plan for meeting its cold-snap standard for one heating season on a division-specific basis (Exh. CGC-1; Brief, p. 10). The Company stated that in modelling the sendout for its cold-snap analysis, it made the following assumptions: (1) design weather conditions occur in the months of November and December prior to the cold-snap beginning in January; (2) storage and supplemental inventories are full at the beginning of the heating season; (3) no Iroquois-delivered volumes are relied upon; and (4) no additional "injections beyond firm Bay State LNG" are included (Tr. 1, p. 12; Exh. CGC-1).

b. Analysis

The Siting Council finds that the Company's choice of a cold-snap standard based upon an actual period of extreme weather is reasonable. Additionally, the Company's choice of design year weather conditions for the heating season leading up to the cold-snap represents a sound basis for supply planning. Accordingly, the Siting Council finds that the Company's choice of a cold-snap standard is appropriate for a company of its size and resources.

The Siting Council also finds that the Company has established that it has an adequate supply plan to meet its firm sendout requirements in the event of a cold-snap during the first year of the forecast period. The Siting Council notes that the Company has sufficient LNG and propane inventories such that purchases during a cold-snap period should not be necessary.

The Siting Council notes, however, that the Company's future ability to meet firm sendout requirements depends on (1) its continued ability to ensure full storage volumes and (2) pipeline transportation availability. This ability may be markedly affected by the timing of future increases in firm pipeline supplies to New England generally and to Colonial specifically. Consequently, the Company should be prepared in future forecast reviews to establish the continued adequacy of its cold-snap supply plan in light of then current supply scenarios.

The Siting Council has found that the Company's choice of a cold-snap standard is appropriate, and that the Company has established that it has an adequate supply plan to meet its firm sendout requirements in the event of a cold-snap during the first year of the forecast period.

Accordingly, the Siting Council finds that Colonial has established that it has adequate resources to meet its firm sendout requirements under cold-snap conditions during the first year of the forecast period. Further, the Siting Council finds that Colonial has complied with the ORDER in our previous decision requiring the Company to submit a cold-snap analysis or explain why such an analysis is unnecessary to demonstrate cold-snap preparedness.

4. Conclusions on the Adequacy of the Supply Plan

The Siting Council has found that the Company has established that (1) its base case, normal year and design year supply plans are adequate to meet the Company's forecasted firm sendout and storage refill requirements on a division-specific basis throughout the forecast period and (2) its base case supply plan is adequate to meet the Company's forecasted firm design day sendout requirements for both divisions in all years of the forecast period. The Siting Council has found that Colonial has adequate resources to meet forecasted firm design year sendout requirements in both divisions in the event of either: (i) an indefinite delay in the delivery of 302 BBtu of ANE supplies from the Iroquois project to the Lowell Division; (ii) termination of the fuel-sharing agreements for 165 BBtu for the Lowell Division; or (iii) termination of an agreement for delivery of 232.6 BBtu to the Cape Division. In addition, the Siting Council has found that Colonial has adequate resources to meet forecasted firm design day sendout requirements in both divisions in the event of either: (i) an indefinite delay in the delivery of 2.0 BBtu per day of ANE supplies from the Iroquois project to the Lowell Division; (ii) termination of the fuel-sharing agreements with cogenerators for 15.6 BBtu per day for the Lowell Division; or (iii) termination of an agreement for delivery of 2.326 BBtu per day to the Cape Division.

Further, the Siting Council has found that the Company has established that it has adequate resources to meet its firm sendout requirements under cold-snap conditions during the first year of the forecast period. Finally, the Siting Council has found that Colonial has complied with the order in our previous decision requiring the Company to submit a cold-snap analysis or explain why such an analysis is unnecessary to demonstrate cold-snap preparedness.

Accordingly, the Siting Council finds that Colonial has established that it has adequate resources to meet its firm sendout requirement throughout the forecast period.

F. Least-Cost Supply

1. Standard of Review

As set forth in Section III.A, above, the Siting Council reviews a gas company's five-year supply plan to determine whether it minimizes cost, subject to trade-offs with adequacy and environmental impact. 1990 Berkshire Decision (Phase 1), 19 DOMSC at 282; 1989 Bay State Decision, 19 DOMSC at 180; 1989 Fitchburg Decision, 19 DOMSC at 100; 1988 ComGas Decision, 17 DOMSC at 109; 1987 Bay State Decision, 16 DOMSC at 309; 1987 Berkshire Decision, 16 DOMSC at 72; See: 1989 MECo Decision, 18 DOMSC at 337. A gas company must establish that the application of its supply planning process -- including adequate consideration of C&LM and consideration of all options on an equal footing -- has resulted in the addition of resource options that contribute to a least-cost supply plan. As part of this review, the Siting Council continues to require gas companies to show, at a minimum, that they have completed comprehensive cost studies, comparing the costs of a reasonable range of practical supply alternatives, prior to selection of major new resources for their supply plans. 1990 Boston Gas Decision, 19 DOMSC at 438; 1989 Bay State Decision, 19 DOMSC at 224; 1989 Fitchburg Decision, 19 DOMSC at 123-124; 1987 Bay State Decision, 16 DOMSC at 319; 1986 Gas Generic Order, 14 DOMSC at 100-102.

2. Supply Cost Analysis

In its Decision in the 1986 Gas Generic Order, the Siting Council found that it was appropriate to focus on that portion of its mandate that requires the Siting Council to ensure an energy supply for the Commonwealth "at lowest possible cost." G.L. c. 164, sec. 69H. In so doing, the Siting Council must evaluate whether a company assesses the relative costs of the various resource options it could use to meet its resource needs. This evaluation is critical to least-cost planning since each option may feature unique cost, reliability and other non-price characteristics and since different load additions with varying gas usage patterns impose different types of supply obligations in terms of cost and other non-price characteristics.[40]

In the Siting Council's most recent Colonial decision, the Company was directed to perform an internal study comparing the costs of a reasonable range of practical supply alternatives in the event that the Company's filing proposed the acquisition of a new long-term firm gas supply contract. 1986 Colonial Decision, 14 DOMSC at 291-292. The preparation of such internal studies is consistent with the Siting Council's Decision in the 1986 Gas Generic Order and was required in order to ensure that the Company's plan minimizes cost.

In the instant case, the Company's obligation to perform such a study was triggered by Colonial's decision to add the NOREX, ANE, and Sonat volumes -- all of which are firm pipeline supplies. Such a study was also required by the Company's decisions to add the PSS-T, Distrigas LNG, and Bay State LNG volumes, as well as fuel-sharing agreements for supplemental volumes. All of the foregoing additions constitute firm supplies that require the Company to perform a cost study in order to evaluate whether the resources were least-cost additions to the Company's existing supply plan, taking adequacy and reliability concerns into account. Thus, seven new major

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40/ In the 1989 Fitchburg Decision, the Siting Council found that a company has not performed a comprehensive cost study if: (1) it does not include a sensitivity analysis and does not explicitly analyze tradeoffs between price and non-price factors; (2) it does not analyze and describe how the daily and annual quantities of new supplies were determined; and (3) it fails to consider a reasonable range of practical supply alternatives including available C&LM programs (19 DOMSC at 125).

supply additions have been made since the 1986 Colonial Decision in which the Siting Council identified the need for comprehensive cost studies.[41]

a. Supply Additions

The Company provided no evidence that a comprehensive cost study had been completed for any of these seven supply additions. The ANE project illustrates this point.

The Company did provide estimated cost information for the ANE project for the years 1989 and 1990.[42] Colonial also compared the cost of delivering this gas through the Iroquois pipeline to the Cape Division with the cost of delivering this same gas through the proposed Champlain pipeline (Exh. CGC-8). The cost information, however, is based on an assumed 100 percent load factor for the volumes, an assumption for which the Company provided no supporting documentation. In addition, no allowance was made for future price variations (id.). Thus, although Colonial here has provided estimated cost information of the ANE project and a comparison of transportation costs, it has failed to: (1) justify its assumptions; (2) provide an analysis of the project that considered its cost justification under differing future price scenarios; (3) compare costs of the ANE volumes to other supply options, including C&LM; (4) compare the cost of the planned ANE volumes to the costs of alternative volumes in order to determine what volume would be optimal; or (5) consider the tradeoffs between cost and non-cost criteria.

Similar shortcomings can be found in Colonial's six other identified supply additions. In addition, the Company has not

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41/ The Siting Council recognizes that Colonial has conducted cost evaluations of its C&LM programs (see Section III.F.2.b, below).

42/ Colonial indicated that the ANE supplies are expected to be available in part in 1991 and fully in 1992 (Exh. CGC-8).

provided complete cost information for any of the identified supply additions.[43] It appears clear, therefore, that the Company has not performed the required cost studies.

Accordingly, the Siting Council finds that Colonial has failed to establish that the NOREX, PSS-T Service, fuel-sharing, ANE, Sonat, Distrigas LNG, and Bay State LNG supply additions contribute to a least-cost supply plan.

b. Conservation

As discussed in Section III.D.2, above, Colonial has recently implemented two conservation programs as a "ramp-up" to a full-scale program: a weatherization program for fuel assistance customers and a zero-interest loan program for residential customers. In the fall of 1991, subject to MDPU approval, Colonial will be implementing a "full-scale" conservation program which includes programs for residential,

43/ With respect to the two Distrigas LNG purchases, Colonial provided a table of the average cost of Cape Division LNG supplies for the years 1984 through 1990 which the Company asserted "illustrates, Colonial's LNG cost at the Cape has been reduced since the inception of the [1989 Distrigas] agreement" (Exh. CGC-8).

The analysis of Cape Division LNG costs is insufficient to determine what impact, if any, the Distrigas LNG contracts have on the division's overall gas costs. Colonial provided no comparison of the costs over time of alternatives of either of the two Distrigas LNG purchases. Nor did the Company indicate what the current commodity and demand charges are under the two contracts. The analysis of average costs provided by the Company illustrates a reduction of LNG costs over past years; such an analysis would be directly relevant to a comprehensive cost study that the Company is required to perform if the analysis illustrated that these specific LNG supplies would provide a reduction of (average) costs over future years when compared to viable alternative supplies.

Without future cost analyses for options and viable alternatives, the Company does not have a comprehensive cost study on which to base supply decisions.

commercial and industrial customers.[44]

In selecting the measures to be included in both the ramp-up program and the full-scale program, Colonial compared the cost of each measure, and the energy savings it would produce, to the Company's avoided cost for gas as documented in the LaCapra study.[45] LaCapra developed separate avoided cost figures for Colonial's two divisions, based on an unidentified supply delivered via the Iroquois pipeline as the avoided supply block for the Lowell Division, and Penn East CDS supplies as the avoided supply block for the Cape Division (Exh. HO-S-20, p. 40). LaCapra also developed separate avoided costs for peak load and base load conservation, resulting in a set of four avoided costs for Colonial: Lowell Division peak, Lowell Division base load, Cape Division peak, and Cape Division base load (id., p. 46).

The Company stated that it selected the measures in its original proposal for a pilot study based on a cost-benefit analysis performed by Xenergy (Tr. 1, p. 132). During the course of hearings before the MDPU, the cost-benefit analysis was updated to take into account interactions between measures (Exh. HO-1B, Section VI, p. 77).

44/ The Siting Council notes that its current review is of the Company's 1989 Forecast. The Company's full-scale conservation program, however, was not a part of the 1989 Forecast. Nevertheless, the Siting Council reviews the program here with the understanding that this program will become a part of the Company's least-cost supply plan in future filings and because the program incorporates an avoided-cost study, the nature of which responds to the Siting Council's order in the 1986 Colonial Decision to perform an internal study comparing the costs of a reasonable range of practical supply alternatives (14 DOMSC at 291-292).

45/ The LaCapra study was updated to incorporate environmental externalities before being used to develop the full-scale program (Exh. HO-RR-4, Stavropoulos Testimony, p. 7) The updated LaCapra study also reflects a reduction in the Company's discount rate and a change in the base year used to calculate present value figures (id.).

Colonial stated that it selected measures to be included in its full-scale conservation program based on a technical potential study performed by EII (Tr. 1, p. 110). The Company noted that EII used Colonial-specific MASS-SAVE audit data to select measures which would be cost-effective for Colonial customers, and to determine the potential savings available from these measures (id., pp. 110-111). The Company stated that the technical potential study first determined individual measure cost-effectiveness by comparing each measure's cost to Colonial's avoided cost; then measures were bundled to determine whether they remained cost-effective after accounting for interactive effects (Exh. HO-RR-4, Gillette Testimony, pp. 5-6).

The Company stated that it had not tested the sensitivity of the technical potential study's results to changes in assumptions about measure costs or estimated savings (Tr. 1, pp. 126-127) The Company noted, however, that EII applied a 20 percent discount to the MASS-SAVE savings estimates which it used in the technical potential study (id., pp. 128-129).

The Company stated that it compared the cost of base measures, such as a tank wrap, to base avoided costs, and peak measures to peak avoided costs (id., p. 123). The Company noted that it would offer specific measures only in those divisions, and only to those customer classes, where they would be cost-effective (id., p. 124). The proposal for the full-scale residential program indicates that different measures will be offered in the Company's different divisions, and that single-family residences will be offered different measures than multi-family residences (Exh. HO-RR-4, Gillette Testimony, p. 7).

Colonial has developed an extensive process to ensure the cost-effectiveness of its full-scale conservation program. The use of division-specific and load-specific avoided costs and Company-specific audit data ensures that the conservation measures offered by Colonial are appropriate for Colonial customers. The discounting of MASS-SAVE savings estimates ensures that the expected benefits of the proposed program are not overstated.[46]

The Company has also given careful consideration to the incentive levels offered in its program, balancing desired penetration rates against the cost to ratepayers, and taking into account its experience with the zero-interest loan program. The Siting Council expects that incentive levels will continue to evolve as the Company acquires more information on program participation at various incentive levels.

The Siting Council has consistently held that C&LM programs are not exempt from the Siting Council's requirements under the 1986 Gas Generic Order that gas companies complete comprehensive cost studies comparing the costs of a reasonable range of practical supply alternatives in their analysis of major new supply options (14 DOMSC at 102). In a previous decision, the Siting Council has found that an avoided cost study is an appropriate means of satisfying our requirement to compare the cost of conservation programs with the cost of a reasonable range of supply alternatives. 1990 Boston Gas Decision, 19 DOMSC at 458-459. Here, the Company has presented a detailed avoided cost study and technical potential study, and has carefully considered the effects of various incentive levels on program participation and customer rates. Therefore, the Siting Council finds that the Company has established that its full-scale conservation program will contribute to a least-cost

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46/ The Siting Council notes that, if the 20 percent discount rate is too high, some cost-effective measures may have been excluded from these programs. We accept that the MASS-SAVE savings estimates, which are the result of energy audits of a self-selected group of customers, may be overstated, and that some level of discounting may result in a more reasonable estimate of savings. While discounting may be justified in this instance, the Company generally should not discount estimates of conservation savings unless it can document that the methodology used to derive those estimates biases the results upward.

supply plan.

The Siting Council notes, however, that the Company has not included the resource savings from these conservation programs in its base case supply plan. Further, the Company has stated that it has not yet decided how to incorporate conservation resources into its supply planning process (Tr. 1, pp. 161-162).[47] The Siting Council recognizes that Colonial's full-scale conservation program was developed at a very late point in these proceedings, and that the Company could not have included estimated savings from this program in either the 1989 or the 1990 Forecasts. However, the Siting Council is concerned that the continued exclusion of conservation resources from the base case supply plan could lead the Company to overestimate its need for supplemental resources, and, as a consequence, to purchase unnecessary supplies.

Colonial has indicated that it intends to participate in the GEMS study,[48] a project coordinated by the Boston Gas Company, which will gather end-use data to determine the gas savings associated with various conservation measures (id., pp. 145-147). The MDPU is currently reviewing the project in D.P.U. 90-320 (Exh. HO-RR-4, Griffin Testimony, pp. 37-38). Colonial also has developed plans to collect data on the savings resulting from its own programs, should the GEMS program not be implemented (id., pp. 38-47).

Overall, Colonial has made significant efforts to obtain accurate data on the savings to be expected from the installation of various conservation measures. The Siting Council expects Colonial to continue these efforts. Therefore,

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47/ Colonial indicated that it has formed an Integrated Resource Management team which will discuss these issues (Tr. 1, pp. 161-162; Brief, p. 9).

48/ GEMS is an acronym for Gas Evaluation and Monitoring Study.

the Siting Council ORDERS the Company in its next filing to (1) quantify the savings due to its existing and planned C&LM programs over the forecast period and (2) fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions.

3. Compliance with Order Five

In the 1986 Colonial Decision, the Siting Council ordered Colonial to comply with the 1986 Gas Generic Order (14 DOMSC at 290-292). The Siting Council identified in these orders the types of contractual arrangements proposed by a gas company that require a cost study.

Based on the above, Colonial has failed to establish that it has complied with the Siting Council order to perform a cost study for seven supply additions. This failure raises serious questions about the ability of the Company to make informed, cost-justified supply planning decisions. In particular, the Company failed to provide any written documentation describing the decision framework used to determine what, if any, amounts of the proposed new supplies or other options, would ensure a least-cost, reliable supply plan for the Company's firm customers (see Section III.F.2.a).

Accordingly, the Siting Council finds that Colonial has not complied with Order Five of the previous decision in so far as it required the Company to provide a cost study of a reasonable range of supply alternatives in the event that the Company's filing indicated the need for a new long-term firm gas supply contract. Therefore, the Siting Council ORDERS Colonial, in its next forecast filing, to provide a cost study of a reasonable range of supply alternatives, with each alternative analyzed at varied annual and daily quantities and capacity factors, over varied time periods, in the event that the Company has obtained, plans to obtain, or forecasts a need for new firm gas supplies for a period of more than one year.

4. Conclusions on Least-Cost Supply

The Siting Council has found that the Company has failed to establish that the NOREX, PSS-T Service, fuel-sharing, ANE, Sonat, Distrigas LNG, and Bay State LNG supply additions contribute to a least-cost supply plan. The Siting Council has also found that the Company has established that its full-scale conservation program will contribute to a least-cost supply plan. Finally, the Siting Council has found that Colonial did not comply with Order Five of the previous decision requiring a cost study of a reasonable range of supply alternatives in the event that the Company's filing indicated the need for a new long-term firm gas supply contract.

Accordingly, the Siting Council finds that, on balance, Colonial has failed to establish that its supply decisions contribute to a least-cost supply plan.

G. Conclusions on the Supply Plan

The Siting Council has made no finding as to whether the Company's supply planning process enables it to make least-cost supply decisions. The Siting Council has found that (1) Colonial has adequate resources to meet its firm sendout requirements throughout the forecast period and (2) Colonial has failed to establish that its supply decisions contribute to a least-cost supply plan.

In issuing this Decision, the Siting Council notes that Colonial has demonstrated that it is able and willing to improve its supply planning process as its efforts in conservation and conversion of pipeline capacity for transportation-sharing illustrate. Nonetheless, the Company's failure to evaluate the appropriate level of participation in new supply projects subjects the Company's ratepayers to paying for supplies which may, in fact, be unnecessary.

Further, the Company's failure to establish that its supply plan is least-cost is a serious flaw in the Company's supply planning process. Colonial's lack of cost studies in support of its supply acquisitions prevents the Company from determining whether its purchases are optimal. In the absence of such studies, the Company has taken the risk that its ratepayers may be paying for a higher cost supply than is necessary, both at present and in the future. In addition, the Siting Council has specifically required Colonial to perform these cost studies in two separate decisions, but Colonial has failed to do so.

The Siting Council emphasizes the importance of the Orders and instructions contained in this Decision as beneficial to the Company's supply planning process. The Siting Council expects that the Company will improve its supply planning process through its compliance with these Orders and its continued efforts to adapt to the rapid changes occurring in the natural gas industry.

Accordingly, the Siting Council hereby REJECTS the 1989 supply plan of Colonial Gas Company.

IV. DECISION AND ORDER

The Siting Council hereby REJECTS the sendout forecast and supply plan of Colonial Gas Company as presented in its Fourth Supplement to its Third Long-Range Forecast.

The Siting Council ORDERS Colonial in its next forecast filing:

(1) to report the accuracy of their five proceeding sendout forecasts for both the Cape and Lowell Divisions using Table FA and to discuss the sources of inaccuracies and their implications on the reliability of the Company's forecast methodologies;

(2) to present (a) an analysis of potential sendout forecasting improvements that may result from the use of EDD in the Lowell Division; (b) an analysis of the costs that would be incurred if the Company were to collect EDD from available sources; and (c) an analysis of the feasibility of using EDD in the Lowell Division;

(3) to (a) develop design year standards based on appropriately analyzed probability of occurrence criteria; (b) describe the costs associated with those design year standards and their associated reliability impacts over the forecast period; and (c) describe other probability criterion levels considered for the forecast period and their costs and reliability impacts;

(4) to (a) develop design day standards based on appropriately analyzed probability of occurrence criteria; (b) describe the costs associated with those design day standards and their associated reliability impacts over the forecast period; and (c) describe other probability criterion levels considered for the forecast period and their costs and reliability impacts;

(5) to (a) fully describe the methodology used to develop its projection of usage factors; (b) provide complete documentation of the assumptions used in its forecasts of usage factors; (c) fully describe its methodology for identifying and selecting variables on which its forecasts of usage factors are based; and (d) perform sensitivity analyses based on inclusion of variables identified in (c) above.

(6) to (a) fully describe the methodology used to develop its projection of customer numbers; (b) provide complete documentation of the assumptions used in its forecasts of customer numbers; (c) fully describe its methodology for identifying and selecting variables on which its forecasts of customer numbers are based; and (d) perform sensitivity analyses based on the inclusion of variables identified in (c) above.

(7) to (a) develop and apply a new design day forecast methodology or (b) fully document its assumptions regarding the relationship between monthly heating usage factors in normal weather and daily heating usage factors in design weather.

(8) to develop a comprehensive evaluation process based on specific written criteria that it will employ in the evaluation of all pipeline supply options, and to provide a complete description of how these criteria were applied to each pipeline supply option identified and evaluated by the Company;

(9) to develop a comprehensive evaluation process based on specific written criteria that it will employ in the evaluation of all supplemental supply options, and to provide a complete description of how these criteria were applied to each supplemental supply option identified and evaluated by the Company;

(10) to identify specific non-price criteria which will be used to evaluate conservation resources, as well as describe how each of these non-price criteria was applied to each conservation resource identified and evaluated by the Company;

(11) to include in its next filing an explicit discussion of how it identifies and evaluates load management options, including a stated rationale or policy on the conversion of interruptible customers to firm service;

(12) to (a) quantify the savings due to its existing and planned C&LM programs over the forecast period and (b) fully incorporate these estimates into its base case resource plan and its analyses of adequacy for normal and design conditions; and

(13) to provide a cost study of a reasonable range of supply alternatives, with each alternative analyzed at varied annual and daily quantities and capacity factors, over varied time periods, in the event that the Company has obtained, plans to obtain, or forecasts a need for new firm gas supplies for a period of more than one year.

The Siting Council further ORDERS Colonial to file its next forecast on November 1, 1992.

Robert P. Rasmussen

Robert P. Rasmussen
Hearing Officer

TABLE 1

Colonial Gas Company
Forecast of Firm Sendout by Customer Class
(BBtu)

Customer Class	1989-1990			1993-1994		
	Normal Heating Season	Normal Non-Heating	Design	Normal Heating Season	Normal Non-Heating	Design
Lowell						
Res. Heating	4702	1816	5121	4908	1904	5345
Res. Non-Heat	49	51	49	42	44	42
Com/Indus.	3479	1708	3768	3573	1756	3869
Co. Use/UFG[1]	293	192	310	300	195	318
Lowell Total	8523	3767	9248	8823	3899	9574
Cape Cod						
Res. Heating	2855	1279	3179	3433	1511	3831
Res. Non-Heat	59	99	59	58	98	58
Commercial[2]	1491	951	1627	1783	1144	1940
Co. Use/UFG[1]	144	74	158	170	87	187
Cape Cod Total	4549	2403	5023	5444	2840	6016
COMPANY TOTAL	13072	6170	14271	14267	6739	15590

Note:

1. Includes Company-use and unaccounted-for gas.

2. Includes Otis Air Force Base use.

Sources: Exh. HO-1A, Tables G-1 through G-5.

TABLE 2A
Colonial Gas Company
Lowell Division
Base Case Design Year Supply Plan
Heating Season
(MMcf)[1]

	1990-91	1991-92	1992-93	1993-94
FIRM SENDOUT:	9322	9378	9471	9575
RESOURCES				
Tennessee CD-6	7450	7550	7550	7550
Tenn. Storage return	1278	1213	1231	1292
Alberta-Northeast	0	302	302	302
Cogenerator Fuel Swaps	0	105	107	122
LNG from Storage	590	374	449	492
Firm LNG	286	386	186	211
Propane from Storage	110	45	45	45
TOTAL RESOURCES:	11176	11628	11428	11423
SURPLUS (DEFICIT)	678	1863	1772	1653
RESERVE	7.3%	19.9%	18.7%	17.3%

Notes:

1. This table assumes that 1 BBtu equals 1 MMcf.

Sources: Exhs. HO-1A, Tables G-5, G-22; HO-S-15

TABLE 2B
Colonial Gas Company
Cape Cod Division
Base Case Design Year Supply Plan
Heating Season
(MMcf)[1]

	1990-91	1991-92	1992-93	1993-94
FIRM SENDOUT:	5314	5555	5780	6016
RESOURCES				
Algonquin F-1	1724	1748	1748	1748
Algonquin F-2	260	290	290	290
Algonquin F-3	76	86	86	86
Algonquin F-4	1190	1181	1181	1181
Algonquin WS-1	285	293	293	293
AGT Storage return	693	775	775	775
LNG from Storage	347	429	646	878
Firm LNG	920	925	905	905
Propane from Storage	37	16	24	28
TOTAL RESOURCES:	6202	6034	6210	6442
SURPLUS (DEFICIT)	670	291	262	258
RESERVE	12.6%	5.2%	4.5%	4.3%

Notes:

1. This table assumes that 1 BBtu equals 1 MMcf.

Sources: Exhs. HO-1A, Tables G-5, G-22; HO-S-15

TABLE 3A
Colonial Gas Company
Lowell Division
Comparison of Resources and Requirements
Design Day
(MMcf)[1]

	1990-91	1991-92	1992-93	1993-94
FIRM SENDOUT:	117.7	118.5	119.8	121.2
RESOURCES				
Tennessee CD-6	50.0	50.0	50.0	50.0
Tenn. Storage return	15.8	15.8	15.8	15.8
Cogenerator Fuel Swaps	0	15.6	15.6	15.6
Alberta-Northeast	0	1.7	2.0	2.0
LNG from Storage	78.3	78.3	78.3	78.3
Propane from Storage	26.0	26.0	26.0	26.0
TOTAL RESOURCES:	170.1	189.7	189.7	189.7
SURPLUS (DEFICIT)	53.0	71.2	69.9	68.5
RESERVE	44.5%	60.1%	58.3%	56.5%

Notes:

1. This table assumes that 1 BBtu equals 1 MMcf.

Sources: Exhs. HO-1A, Table G-23, HO-1B, Table G-23

TABLE 3B
Colonial Gas Company
Cape Cod Division
Comparison of Resources and Requirements
Design Day
(MMcf)[1]

	1990-91	1991-92	1992-93	1993-94
FIRM SENDOUT:	67.8	70.6	73.5	76.3
RESOURCES				
Algonquin F-1	11.6	11.6	11.6	11.6
Algonquin F-2	1.9	1.9	1.9	1.9
Algonquin F-3	.6	.6	.6	.6
Algonquin F-4	7.9	7.9	7.9	7.9
Algonquin WS-1	4.9	4.9	4.9	4.9
AGT Storage return	6.2	6.2	6.2	6.2
LNG from Storage	31.2	31.2	31.2	31.2
Firm LNG	10.0	10.0	10.0	10.0
Propane from Storage	9.7	9.7	9.7	9.7
TOTAL RESOURCES:	84.0	84.0	84.0	84.0
SURPLUS (DEFICIT)	16.2	13.4	10.5	7.7
RESERVE	23.9%	19.0%	14.3%	10.1%

Notes:

1. This table assumes that 1 BBtu equals 1 MMcf.

Sources: Exhs. HO-1A, Table G-23, HO-1B, Table G-23

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 8, 1991 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria C. Larson, Secretary of Consumer Affairs and Business Regulation; Brandt Sakakeeny (for Daniel S. Gregory, Secretary of Economic Affairs); Andrew Greene (for Susan F. Tierney, Secretary of Environmental Affairs); Chris Donodeo Cashman (for Paul W. Gromer, Commissioner of Energy Resources); and Kenneth Astill (Public Engineering Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 8th day of November, 1991

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 be 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 service 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 the 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. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council
Department of Public Utilities

Petition of Massachusetts Electric Company and New England Power Company, pursuant to General Laws Chapter 164, Section 69H, 76, 94, 94B and 96G, and 220 CMR 10.00 and 980 CMR 12.00 et seq. (Integrated Resource Management Regulations) for review of the procedures by which additional energy resources are planned, solicited, and procured by Massachusetts Electric Company and New England Power Company.	)	EFSC 91-24 DPU 91-114

FINAL ORDER

Ronald F. LeComte
Hearing Officer
Energy Facilities Siting Council

Jeffrey M. Leupold
Hearing Officer
Department of Public Utilities

November 8, 1991

APPEARANCES: Thomas G. Robinson, Esq.
Mark E. Slade, Esq.
Massachusetts Electric Company
25 Research Drive
Westborough, Massachusetts 01582
FOR: MASSACHUSETTS ELECTRIC COMPANY
NEW ENGLAND POWER COMPANY
Petitioners

Attorney General L. Scott Harshbarger
By: Edward Bohlen, Esq.
Assistant Attorney General
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Paul B. Dexter, Esq.
Meabh Purcell, Esq.
LeBoeuf, Lamb, Leiby & MacRae
260 Franklin Street
Boston, Massachusetts 02110
FOR: FITCHBURG GAS AND ELECTRIC
LIGHT COMPANY
Intervenor

Alan J. Nogee
MassPIRG
29 Temple Place
Boston, Massachusetts 02111
FOR: MASSPIRG
Intervenor

Seth Tuler
Massachusetts Save James Bay, Inc.
945 Main Street
Box 917
Worcester, Massachusetts 01610
FOR: MASSACHUSETTS SAVE JAMES BAY
Intervenor

Edward L. Selgrade, Esq.
Tillinghast, Collins & Graham
303 Congress Street
Boston, Massachusetts 02110

and

Edward T. Liston
EUA Cogenex Corporation
100 Foot of John Street
Lowell, Massachusetts 01852
FOR: ENERGY ENGINEERS TASK FORCE
Intervenor

Andrew J. Newman, Esq.
Rubin & Rudman
50 Rowes Wharf
Boston, Massachusetts 02110
FOR: THE ENERGY CONSORTIUM
Intervenor

Dennis J. Duffy, Esq.
Partridge, Snow & Hahn
180 South Main Street
Providence, Rhode Island 02903
FOR: LONG LAKE ENERGY CORPORATION
Intervenor

Christine Constas Erickson, Esq.
Commonwealth of Massachusetts
Division of Energy Resources
100 Cambridge Street
Boston, Massachusetts 02202
FOR: DIVISION OF ENERGY RESOURCES
Intervenor

Robert N. Werlin, Esq.
John A. DeTore, Esq.
David S. Rosenzweig, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, Massachusetts 02110
FOR: NEW ENGLAND COGENERATION ASSOCIATION
Intervenor

Catherine J. Keuthen, Esq.
Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199
FOR: BOSTON EDISON COMPANY
Intervenor

Robert L. Dewees, Jr., Esq.
Peabody & Brown
101 Federal Street
Boston, Massachusetts 02110

and

Philip M. Small, Esq.
Terry C. Ranger
Northeast Utilities Service Company
P.O. Box 270
Hartford, Connecticut 06141
FOR: WESTERN MASSACHUSETTS ELECTRIC COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
Intervenors

John Traficante, Esq.
Cabot Power Corporation
200 State Street
Boston, Massachusetts 02109
FOR: CABOT POWER CORPORATION
Intervenor

John B. Howe
West Lynn Cogeneration
One Bowdoin Square
Boston, Massachusetts 02114
FOR: WEST LYNN COGENERATION
Intervenor

Armond Cohen, Esq.
Conservation Law Foundation
of New England, Inc.
3 Joy Street
Boston, Massachusetts 02108
FOR: CONSERVATION LAW FOUNDATION
OF NEW ENGLAND, INC.
Intervenor

Michael F. Donlan, Esq.
Emmett E. Lyne, Esq.
James M. Avery, Esq.
Rich, May, Bilodeau & Flaherty
294 Washington Street
Boston, Massachusetts 02108
FOR: COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
Interested Persons

John F. Smitka, Jr., Esq.
Kevin Kirby
Eastern Edison Company
One Liberty Square
P.O. Box 2333
Boston, Massachusetts 02107
FOR: EASTERN EDISON COMPANY
Interested Person

Laurie Martinelli
Massachusetts Audubon Society
South Great Road
Lincoln, Massachusetts 01773
FOR: MASSACHUSETTS AUDUBON SOCIETY
Interested Person

Alexander B. Belisle
59 Grafton Street
Milbury, Massachusetts 01527
PRO SE
Interested Person

Robert E. Charlton
29 Lois Lane
Billerica, Massachusetts 01821
PRO SE
Interested Person

Francis H. Cummings
Cummings Consulting, Inc.
123 Minot Road
Concord, Massachusetts 01742
FOR: CUMMINGS CONSULTING, INC.
Interested Person

Peter W. Wallis
Wallis Energy Company
33 Boston Post Road, Suite 270
Marlborough, Massachusetts 01752
FOR: WALLIS ENERGY COMPANY
Interested Person

FINAL ORDER ON
OFFER OF SETTLEMENT

I. INTRODUCTION

On October 21, 1991, Massachusetts Electric Company ("MECo") and New England Power Company (together, "Companies"), submitted a settlement agreement ("Settlement")[1] to the Department of Public Utilities ("Department") and the Energy Facilities Siting Council ("Siting Council") which, if approved, would resolve all issues in Phase I of the integrated resource management ("IRM") process[2] for the Companies.[3] Generally, the Settlement includes an expanded demand-side RFP[4] and a supply-side RFP, and provides that the Companies will issue the demand-side RFP to acquire 10 megawatts ("MW") of electricity savings, and the supply-side RFP based on a 200 MW resource need commencing in 1997. In addition, the Settlement provides that a

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1/ See Attachment I for a copy of the Settlement and Joint Motion for Approval of Offer of Settlement.

2/ The IRM process is a coordinated review by the Department and Siting Council of the procedures by which additional energy resources are planned, solicited, and procured by an elelctric company. See 220 CMR 10.00 et seq.; 980 CMR 12.00 et seq..

3/ The IRM process contains four Phases. In Phase I, the Siting Council reviews the demand forecast and resource inventory of an electric company and makes a determination on resource need. In this same phase, the Department reviews the company's all resource solicitation requests for proposals ("RFP"). Phase II comprises a company's resource solicitation process, in which a company issues the Department-approved RFP. Phase III comprises the Department's review of a company's award group. Phase IV comprises the Department's procedures for approving contracts in the award group. In Phase IV, the Siting Council adopts the Department's findings as establishing that an electric company has a least-cost, least-environmental-impact supply plan.

4/ The expanded demand-side RFP provides for performance engineering and verification services.

joint decision, either approving or rejecting the Settlement in its entirety, must be reached by the Department and Siting Council by November 8, 1991.

II. PROCEDURAL HISTORY

On May 20, 1991, the Companies filed the draft initial filing with the Department and the Siting Council. On May 23, 1991, the Hearing Officers issued a Notice of Adjudication and directed publication and notification in accordance with 220 CMR 10.03(3) and 980 CMR 12.03(3). The Companies confirmed publication and notification on June 7, 1991.

Petitions to intervene as a party were filed by the Office of the Attorney General ("Attorney General"), Division of Energy Resources, Conservation Law Foundation of New England, Inc. ("CLF"), Massachusetts Public Interest Research Group ("MASSPIRG"), Massachusetts Save James Bay, Energy Engineers Task Force, The Energy Consortium, Western Massachusetts Electric Company/Northeast Utilities ("WMECo/NU"), Boston Edison Company ("BECo"), Fitchburg Gas and Electric Company ("FG&E"), New England Cogeneration Association, Long Lake Energy Corporation, Cabot Power Corporation, and West Lynn Cogeneration.[5] Petitions to participate as an interested person were filed by Commonwealth Electric Company and Cambridge Electric Light Company, Eastern Edison Company, Massachusetts Audubon Society, Cummings Consulting, Inc., Wallis Energy Company, Robert E. Charlton, and Alexander B. Belisle. On July 19, 1991, the Hearing Officers issued a Procedural Order allowing all the petitions to intervene as a party and to participate as an interested person.

On June 24, 1991, the Companies conducted a technical

5/ For the purposes of this decision, intervenors and the Companies are referred to as "Parties".

session to review the draft initial filing.[6] Settlement negotiations began on July 12, 1991.[7] On the same date, the Companies supplemented its draft initial filing to include a draft demand-side and supply-side RFP, and on July 19, 1991 conducted a second technical session for the purpose of reviewing the draft RFP filings. On July 31, 1991, the Department and Siting Council conducted a prehearing conference to establish a procedural schedule for the adjudicatory portion of the proceeding.

On August 23, 1991 the Companies submitted an initial filing and an Offer of Partial Settlement ("Partial Settlement")[8] to the Department and the Siting Council. In the Partial Settlement, the Parties agreed on a complementary demand-side RFP.[9] In addition, the Parties agreed to continue

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6/ Pursuant to the IRM regulations, an electric company is required to hold at least one technical session prior to the initial filing. 220 CMR 10.03(4)(a); 980 CMR 12.03(4)(a). The purpose of the technical session is to provide a basis for exchange of information and clarification of the draft initial filing, and to establish procedures and rules for further discussions designed to limit or settle issues in the draft initial filing. Id.

7/ Pursuant to the IRM regulations, an electric company is required to enter into settlement negotiations with the parties to a proceeding for the purpose of facilitating the Department's and Siting Council's review of the initial filing by (1) evaluating the electric company's draft initial filing and improving all parties' understanding of the draft initial filing, (2) reaching agreement among the parties to the maximum extent possible on the electric company's draft initial filing, (3) making agreed upon improvements to the draft initial filing which will be reflected in the initial filing, and (4) identifying specific areas for adjudication, if necessary, before the Department or Siting Council, or both. 220 CMR 10.03(4)(b); 980 CMR 12.03(4)(b).

8/ The Partial Settlement was signed by all Parties except BECo, WMECo/NU and FG&E. The Companies indicated that these intervenors would not object to the acceptance of the agreement (August 23, 1991 Cover Letter to the Partial Settlement, p. 2).

9/ The complementary RFP complements the Companies existing demand-side management programs.

settlement negotiations on the development of an expanded demand-side RFP and a supply-side RFP, and requested a thirty day continuance of the settlement period to facilitate the continued negotiations.[10] On September 12, 1991, the Department and Siting Council conducted a technical session for the purpose of reviewing the Partial Settlement. On September 20, 1991, the Department and Siting Council, by Joint Order,[11] approved the Partial Settlement.[12]

On October 21, 1991, the Companies submitted the Settlement to the Department and Siting Council.[13] On October 24, 1991, the Department and Siting Council conducted a technical session for the purpose of reviewing the Settlement. On October 25, 1991, the Companies filed a Memorandum in Support of the Offer of Settlement.

III. DISCUSSION AND ANALYSIS

In the Settlement, the Parties agreed to a complementary RFP[14] and an expanded demand-side RFP (Settlement, p. 6). In

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10/ On September 13, 1991, the Parties notified the Department and Siting Council that the continued settlement negotiations would also include issues relating to the determination of resource need. On September 25, 1991 the Parties reported substantial progress in settlement negotiations on all issues. On September 30, 1991, the Parties were granted a thirty day extension of the continuance.

11/ See Attachment II for a copy of the Joint Order and the Partial Settlement.

12/ By letter dated September 20, 1991, the Chairperson of the Siting Council delegated to the Executive Director of the Siting Council the specific responsibility to act on behalf of the Siting Council to accept or reject the Offer of Partial Settlement. See G.L. c. 164, sec. 69H; 980 CMR 2.05(2).

13/ The Settlement was signed by all Parties except the Attorney General, MASSPIRG, CLF and BECo. On October 29, 1991, the Attorney General filed comments on the Settlement. The intervenors not signing the Settlement have indicated they will not object to acceptance of the Settlement.

14/ The complementary RFP was agreed to in the Partial Settlement. The Settlement incorporates the complementary RFP by reference (Settlement, p. 8).

addition, the Parties agreed to a supply-side RFP for qualifying facilities, independent power producers, and nonaffiliated utilities (Settlement, p. 2). While the Companies have asserted that additional resources would not be needed until 2001 (Initial Filing, Vol. III, p. 1), the Parties agreed that the Companies would issue an expanded demand-side RFP based on a target of 10 MW of verified demand reduction, and a supply-side RFP based on a 200 MW resource need commencing in 1997 (Companies Memorandum in Support of Settlement, p. 1).

The Settlement also provides the Companies with the unrestricted option to buy-out certain supply-side contracts executed pursuant to the RFP, at any time before December 31, 1994 (Settlement, p. 2).[15] The Companies note that in the event a buy-out option is exercised, buy-out payments would only be recovered in rates to customers if the Department determines that the payments were prudent (Companies Memorandum in Support of Settlement, p. 4). Therefore, in light of this situation, the Department and Siting Council are confident that the Settlement does not represent an undue risk to MECo's ratepayers.

Based on our review, the Siting Council and Department find the Settlement to be acceptable. The Siting Council and Department further find that the Settlement is not inconsistent with the intent of the IRM process and that the Settlement establishes reasonable procedures by which additional resources will be planned, solicited, and procured. However, we emphasize that our acceptance of the Settlement does not constitute a determination or finding on the merits of any aspect of the Companies initial filing. In addition, we emphasize that our acceptance of the Settlement should not be interpreted as setting a precedent for future IRM filings. In fact, the Siting Council and Department note that the determination of which

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15/ The maximum exposure under the buy-out options is $8 million (Settlement, p. 3). The Companies have agreed to amortize recovery of buy-out costs incurred as a result of the RFP over five years without a return (Companies Memorandum in Support of Settlement, p. 4, n.2).

issues are appropriate for settlement will likely vary substantially from proceeding to proceeding depending upon the particular circumstances of each utility under review.

IV. DECISION AND ORDER

The Siting Council and Department hereby APPROVE the Joint Motion of Offer of Settlement filed by the Companies on October 21, 1991.

The Siting Council ORDERS the Companies to file an intercycle forecast and supply plan no later than November 20, 1992.[16]

Ronald F. LeComte
Hearing Officer
Energy Facilities Siting Council

Jeffrey M. Leupold
Hearing Officer
Department of Public Utilities

Dated this 8th day of November 1991.

16/ The Siting Council and Department will notify the Companies of the date for the next draft initial filing.

By Order of the Department,

Barbara Kates-Garnick

Barbara Kates-Garnick, Commissioner
Commissioners participating in the decision of D.P.U. 91-114 and EFSC 91-24 were: Webster and Kates-Garnick

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of November 8, 1991 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Gloria C. Larson, Secretary of Consumer Affairs and Business Regulation; Brandt Sakakeeny (for Daniel S. Gregory, Secretary of Economic Affairs); Andrew Greene (for Susan F. Tierney, Secretary of Environmental Affairs); Michael Ruane (Public Electricity Member); and Kenneth Astill (Public Engineering Member).

Gloria C. Larson

Gloria C. Larson
Chairperson

Dated this 8th day of November, 1991

Appeal as to matters of law from any final decision, order or ruling of the Department or 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 Department or the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Department and the Siting Council within twenty days after the date of service of the decision, order or ruling of the Department and the Siting Council, or within such further time as the Department or the Siting Council may allow upon request filed prior to the expiration of the 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. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).