Decision and Orders

Massachusetts Energy Facilities Siting Board

VOLUME 2

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Altresco Lynn, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 91-102

FINAL DECISION

Robert W. Ritchie
Michael Ernst
Hearing Officers
December 15, 1993

On the Decision:

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William Febiger
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TABLES:

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of Altresco Lynn, Inc. to construct a 170 megawatt bulk generating facility and ancillary facilities in Lynn, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Altresco Lynn, Inc. ("Altresco" or "Company") has proposed to construct a 170 megawatt ("MW") natural gas-fired combined-cycle cogeneration facility on a 5.7-acre site at the General Electric ("GE") River Works complex in the City of Lynn, Massachusetts (Exhs. AL-2, p. 1-1; HO-E-4, p. 2-1).

The proposed facility would be powered by natural gas delivered through a new 2.5-mile pipeline constructed by Tennessee Gas Pipeline Company ("Tennessee"), with distillate oil as back-up fuel (Exh. HO-E-4, p. 2-1; Exh. AL-29). A natural gas interconnection line of approximately 1,800 feet would be constructed between a new sales meter station on Tennessee's system and natural gas compressors within the proposed facility (Exh. AL-2, at 3-8). Pursuant to signed contracts and precedent agreements, Altresco will be provided with natural gas on a 365-day-per-year firm basis (Exh. HO-V-11, attachs. 11a-f). The proposed upper limit on the use of oil in the Company's air quality permit is five days per year (Exh. HO-E-4, at 1-1; Tr. 6, at 22).[1] The proposed facility would include an above-ground, 1,450-foot, 12-inch diameter steam line capable of providing GE with at least 55,000 pounds per hour ("lb/hr") of steam for process and heating use (Exhs. AL-2, at 3-1; HO-E-33, at A-1; HO-RR-37). The electricity generated by the proposed facility would be transmitted via two 116-foot, 115 kilovolt ("kV") above-ground interconnection lines to existing utility lines (Exhs. AL-2, p. 3-7; HO-E-1, p. 2-1).

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1 The Company indicated that the back-up fuel that it will burn is very low sulfur distillate oil, which would contain at most 0.05% sulfur, compared to 0.2-0.3% sulfur in ordinary No. 2 distillate oil (Exh. AL-8, at 6).

The major components of the proposed project include: (1) three GE Series 6000 gas turbine generators; (2) three enclosed heat recovery steam generators ("HRSG"); (3) a single condensing turbine generator with a water-cooled condenser; (4) a wet mechanical draft evaporative cooling tower; and (5) three 199-200 foot stacks (Exhs. HO-E-4, at 2-2; HO-E-36S). Additional components include an ammonia storage tank, a 500,000 gallon municipal effluent storage tank, and a 100,000 gallon demineralized water storage tank (Exh. HO-RR-68). Altresco proposes to utilize treated effluent from the Lynn Water and Sewer Commission ("LWSC") as a source of non-potable water for cooling tower make-up (Exhs. HO-E-1, at 5-15; AL-2, at 1-2). Nitrogen oxide ("NOx") emissions would be controlled through the use of advanced low-NOx combustors and Selective Catalytic Reduction ("SCR")[2] (Exh. HO-E-1, at 5-1).

The Company's proposed site is located in an area zoned for heavy industry and consists of developed industrial land currently being used for industrial purposes (Exhs. AL-2, at 1, 13-21; HO-E-71). The proposed site is bounded by residential areas to the north and northwest, by Route 1A (the Lynnway) to the east, by Route 107 (Western Avenue) to the west, and by the Saugus River and marsh areas to the south (Exh. AL-2, at 13-9). The area immediately surrounding the proposed site is predominantly industrial, while the residential neighborhoods surrounding the proposed site in Lynn, Revere and Saugus are of medium density (id. at 12-11; Exh. HO-E-1, at 2-1; Tr. 1, at 90-91).

The Company estimated that construction could be completed in approximately eighteen months and that the proposed facility would cost approximately $181.8 million (Exhs. HO-V-1; HO-RR-88).

Altresco stated that the Company filed an application with the Federal Energy Regulatory Commission ("FERC") for certification of the proposed project as a "Qualifying Facility" ("QF") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA")

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2 SCR is a flue-gas treatment technology that involves injection of ammonia into the turbine exhaust system (Exh. HO-E-1, at 5-2).

(Exh. HO-B-5). The Company stated that FERC issued Order Number QF90-128-000 on the application on August 8, 1990 (id.). The Company provided a self-certification that (1) demonstrates that the proposed facility continues to satisfy QF requirements for operating standards and efficiency standards, and (2) states that no utility or utility holding company owns 50% or more of the project (id.).

Altresco executed a power purchase agreement ("PPA") with Commonwealth Electric Company ("ComElectric") for 25 MW or approximately 14.7 percent of the output from the proposed facility (Exhs. HO-MB-1; H0-MB-12S). The Company presented documentation from the Department of Public Utilities ("Department" or "DPU") approving the power purchase agreement between Altresco and ComElectric on March 18, 1992 (Exh. HO-MB-12S). In addition, Altresco's proposal is the sole project in Boston Edison Company's ("BECo") Request for Proposals ("RFP") 3 Award Group for 132 MW (Exh. HO-RR-30).[3]

Altresco is a subsidiary of Altresco Financial, Inc. ("Altresco Financial"), which is responsible for arranging and overseeing the financing for the proposed project (Exh. AL-2, at 8-1). Altresco Financial has handled the financing for two projects in Massachusetts -- the

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3 The Siting Board takes administrative notice of the following: On June 25, 1993, the Department issued an Order denying a petition filed by BECo on May 20, 1992 seeking to defer further activities in RFP 3. Boston Edison Company, D.P.U. 92-130 (1993). The Department required BECo to begin negotiating a purchase power contract with the RFP 3 Award Group, but suspended BECo's obligation to execute a contract with the Award Group, until the Department issues final Orders in proceedings involving challenges to the rankings in BECo's RFP 3. Id. at 33-34.

On June 30, 1993, BECo filed with the Department a motion for immediate stay of the Department's June 25, 1993 Order in D.P.U. 92-130. In an Order dated July 14, 1993, the Department denied this motion. Boston Edison Company, D.P.U. 92-130-A (1993). On July 14, 1993, BECo filed an appeal of the Department's June 25, 1993 Order with the Massachusetts Supreme Judicial Court ("SJC" or "Court"). As of the date of this decision, the Court has not yet ruled on the appeal.

Altresco Pittsfield cogeneration facility and the Berkshire Gas Pipeline project (HO-V-21).[4]

B. Jurisdiction

Altresco's petition to construct a bulk generating facility and ancillary facilities was filed in accordance with G.L. c. 164, §§ 69H and 69J, which require the Siting Board to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, §69J which requires electric companies to obtain Siting Board approval for construction of proposed facilities at a proposed site before a contruction permit may be issued by another state agency.

As a cogeneration facility with a design capacity of approximately 170 MW, Altresco's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, §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, Altresco's proposals to construct a transmission line and other structures at the site fall within the third definition of "facility" set forth in G.L. c. 164, §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.

4 The Company indicated that Altresco Financial is involved in the early stages of developing projects in Arizona and Nevada, but stated that it has not financed a project outside of Massachusetts. (Exh. HO-B-6; Tr. 4, at 27).

C. Procedural History

On March 29, 1991, Altresco filed with the Energy Facilities Siting Council ("Siting Council")[5] its proposal to construct a 325 MW natural gas-fired cogeneration facility and ancillary facilities in the City of Lynn, Massachusetts. The Siting Council docketed this petition as EFSC 91-102. On July 15, 1991, the Siting Council conducted a public hearing in Lynn. In accordance with the direction of the Hearing Officer, Altresco provided notice of public hearing and adjudication.

Petitions to intervene were filed by the City of Revere, Revere City Councilor John Arrigo, Sheldon Kovitz on behalf of the Point of Pines Beach Association ("Beach Assocation"), Elaine Hurley on behalf of the Pines Riverside Association ("Riverside Association"), West Lynn Cogeneration ("West Lynn"), and Cabot Power Corporation. Petitions to participate as an interested person were filed by the Town of Saugus ("Saugus"), Saugus Selectman Peter Manoogian, and David Ellis, representing the Oakville-Minot Neighborhood Association.

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5 Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), the Siting Council was merged with the Department of Public Utilities ("Department" or "DPU") effective September 1, 1992. Reorganization Act, § 55. Petitions for approval to construct facilities that were pending before the Siting Council prior to September 1, 1992 will be decided by the Siting Board, which is within, but not under the control or supervision of, the Department. Id., §§ 9, 15, 43, 46.

The Reorganization Act provides that all facility petitions before the Siting Board, regardless of when they were filed, will be reviewed consistent with all orders, rules and regulations duly made, all approvals duly granted, and all legal and decisional precedents established by the Siting Council until superseded, revised, rescinded, or cancelled in accordance with law by the Siting Board. Id., § 46.

The Reorganization Act provides further that wherever the name of the Siting Council appears in any general or special law, or in any order, rule, regulation or other document, such name shall mean and shall be construed as referring to the Siting Board or the Department, as appropriate, in accordance with G.L. c. 164, §§ 69G through 69Q. The terms Siting Council and Siting Board will be used throughout this decision as appropriate to the circumstances being discussed.

On October 18, 1991, Altresco submitted a revised petition for construction of a smaller, 170 MW natural gas-fired cogeneration facility and ancillary facilities described in Section I.A., above (Exhs. AL-2; AL-3). In accordance with the direction of the Hearing Officer, Altresco provided a new notice of adjudication.[6] Although the deadline for intervention was extended, no additional petitions for intervention or participation as interested persons were filed. On January 17, 1992, the Hearing Officer conducted a pre-hearing conference at which all petitions to intervene and all petitions to participate as an interested person were allowed. In addition, procedural rules and discovery and hearing schedules were established.

The Siting Council initially conducted 12 days of evidentiary hearings commencing April 16, 1992 and ending June 5, 1992. Altresco presented nine witnesses: Gerald Hill, vice president for health, safety and environmental programs for Altresco, who testified on issues related to site selection, land use, visual impacts, water supply, wastewater, safety and project viability; Howard D. Lutz, president and chief executive officer of Altresco Financial, who testified on the project's financial arrangements and the expertise of the project developers; Jerome M. Gotlieb, vice president of project development for Altresco, who testified on the engineering, procurement and construction contracts; Douglas L. Corbett, an independent consultant, who testified regarding fuel supply and transportation; Michael T. Carroll, manager of plant utilities for GE River Works, who testified on the site lease and steam agreements between GE and Altresco; Richard La Capra, utility analyst and principal of La Capra Associates, who testified on the need for the project, Massachusetts benefits, and alternative energy resources; George S. Lipka, a consultant with HMM Associates, Inc. ("HMM"), who testified regarding air quality and traffic issues; David N. Keast, an acoustical consultant, who testified on noise issues; and Charles J. Natale, a

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6 The Hearing Officer directed the Company to undertake the same notification process as for the initial notice of adjudication. However, since the revised proposal was basically the same as the original proposal, with the primary difference being the smaller size and associated reduced impacts, no additional public hearing was held.

consultant with HMM, who testified regarding environmental issues. None of the intervenors presented witnesses.

Pursuant to a schedule established by the Hearing Officer, the Company filed its initial brief ("Company Initial Brief") on July 3, 1992. Saugus filed what it characterized as a brief ("Saugus Initial Brief") on July 17, 1992.[7] On July 22, 1992, the Company filed the Opposition of Altresco Lynn, Inc. to the Town of Saugus' Post-Hearing Brief. Saugus filed a reply letter to the Company Opposition to the Saugus Brief on July 29, 1992.

The Beach Association filed its initial reply brief ("Beach Association Initial Brief") on July 23, 1992. In accordance with the revised briefing schedule issued by the Hearing Officer, the Company filed its reply brief ("Company Reply Brief") on July 30, 1992. The Beach Association filed a second reply brief ("Beach Association Reply Brief") on August 6, 1992.

On August 31, 1992, Altresco submitted a letter ("Company Letter") to the Siting Council responding to the SJC's Decision in City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"). In City of New Bedford, the SJC remanded the conditional approval of a proposed generating facility to the Siting Council "to compare alternative energy resources" in its review of the proposed project.[8] Id. at 484.

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7 Saugus actually filed a document entitled "Review of Permit Application Materials Submitted to the EFSC for the Proposed Altresco-Lynn Cogeneration Facility", and characterized it as a brief.

8 In City of New Bedford, the SJC also identified four other issues for reconsideration:

> (1) Because the Siting Council's mandate referred to a necessary energy supply for the Commonwealth, the Siting Council's finding that additional energy resources are needed for New England was inadequate (id. at 489);
> (2) The Siting Council must make a finding that the proposed project would produce power at the lowest possible cost (id.);
> (3) The Siting Council must determine that the proposed project would provide a "necessary" energy supply (id. at 489-490); and
> (4) The final decision must be "accompanied by a statement of reasons . . . including determination of each issue of fact or law necessary to the decision . . ." (id. at 490).

In light of the SJC's directive that such a comparison is a necessary element of a Siting Board review of a proposed project, the Company proposed that sections of an earlier version of the Company's filing,[9] which compared the Altresco project to alternative energy resources and technologies, be marked as an exhibit and entered into the record in this proceeding (Company Letter at 1-2). The Company also proposed that all parties be invited to submit supplemental briefs in light of City of New Bedford (id. at 3).

On September 8, 1992, the Beach Association submitted a letter to the Siting Board regarding City of New Bedford ("Beach Association Letter"). The Beach Association requested "an entirely new proceeding, with new discovery, new expert witnesses, new briefs, and new hearings" on alternative energy resources and on the need for the proposed project (Beach Association Letter at 1-3).

On September 16, 1992, the Company responded to the Beach Association Letter ("Company Reply Letter"). The Company acknowledged that a "limited reopening" of the proceedings was necessary to address the alternative energy resources issue (Company Reply Letter at 1-2). However, the Company opposed further proceedings regarding the need for the proposed project because "ample evidence has already been presented" and was the subject of cross-examination and briefing by the Beach Association (id. at 3). The Company further asserted that the implications of City of New Bedford should be addressed in supplemental briefs (id.).

On September 25, 1992, the Hearing Officer issued a Procedural Order reopening the proceeding for the limited purpose of comparing the proposed Altresco project to alternative energy resources.[10] The Company submitted supplemental testimony comparing the

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9 These sections are Chapter 11 of Book 1 and Exhibits 11-A and 11-B of Book 2 of its March 21, 1991 filing.

10 The Hearing Officer found that City of New Bedford did not require the introduction of new testimony, discovery and cross-examination on need issues for the following reasons: "(1) there was ample opportunity to present evidence on need in the original hearings; (2) ample evidence was presented and entered into the record; and (3) the standard of review is essentially the same as the original standard of review." (cites omitted) (Procedural Order of September 25, 1992).

proposed project to alternative energy resources. The Siting Board staff submitted discovery on this supplemental testimony and an evidentiary hearing was held on alternative energy resources on October 30, 1992. Altresco presented two witnesses at this hearing: Richard La Capra, and Gerald R. Hill, both of whom testified regarding alternative energy technologies and their comparison to the proposed project. The Company filed its Supplemental Initial Brief on January 14, 1993, which addressed the comparison of the proposed project and alternative energy approaches ("Company Supplemental Brief").

On October 25, 1992, the Beach Association submitted a motion to "allow the introduction of new testimony, discovery, and cross-examination on need issues in this proceeding." Motion of The Point of Pines Beach Association, Inc. at 1. On October 28, 1992, the Company filed a Response to the Point of Pines Beach Association, Inc. Motion to Reopen the Record ("Company Response to Motion to Reopen"). In its response, Altresco stated that, although it disagreed with the arguments set forth by the Beach Association in its motion, the Company wished to be responsive to the concerns of the intervenors and interested parties in the proceeding and, therefore, proposed to file additional testimony regarding the issue of need for new capacity in Massachusetts, such testimony to be subject to discovery and evidentiary hearings, if necessary. Company Response to Motion to Reopen, at 1-2. The Hearing Officer treated the motion filed by the Beach Association on October 25 as a motion for reconsideration and granted the motion at the evidentiary hearing on October 30, 1992, allowing further testimony, discovery and cross-examination on the issue of the need for power in Massachusetts, including the relationship between the need for power in Massachusetts and the need for regional power.[11]

Additional hearings were held on February 17, 23, and 24, 1993, on the issue of Massachusetts need. Altresco presented one witness at these hearings, Mr. La Capra, who testified regarding need for power in Massachusetts. Altresco filed its Second Supplemental Initial Brief ("Company Second Supplemental Brief") on March 15, 1993. The Beach

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[11] On October 30, 1992 the Company filed with the Siting Board the additional supplemental direct testimony of Richard La Capra on the issue of Massachusetts need.

Association filed its supplemental brief on Massachusetts need ("Beach Association Supplemental Brief"). On March 24, 1993, the Company filed a reply brief on Massachusetts need ("Company Supplemental Reply Brief"). The Beach Association also filed a reply brief on Massachusetts need ("Beach Association Supplemental Reply Brief").

On May 18, 1993, the City of Revere submitted a letter in support of the Beach Association and stated that Altresco failed to adequately demonstrate a Massachusetts need for its proposed facility in accordance with the standards set forth in City of New Bedford, supra.

The Hearing Officer entered 376 exhibits into the record, consisting primarily of information and record request responses. Altresco entered 42 exhibits into the record. The Beach Association entered 47 exhibits into the record. Mr. Arrigo entered one exhibit into the record.

D. Scope of Review

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct facilities, the Siting Board requires applicants to justify generating facility proposals in four phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. Eastern Energy Corporation (on Remand), EFSB 90-100R at 190 (1993) ("EEC (Remand)"); Boston Edison Company, EFSB 90-12/90-12A at 15 (1993) ("1993 BECo Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA"). (see Section II.A. below). Second, the Siting Board requires the applicant to show that, on balance its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability.[12] EEC (Remand), at 65; 1993 BECo Decision, at 15; NEA, 16 DOMSC at 343.

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12 In City of New Bedford, supra, the SJC stated that this standard of review, which was applied by the Siting Council up to 1990, comports with its statutory mandate. 413 Mass. at 485. Subsequent to the Court's ruling, the parties in this proceeding were invited to address in their briefs the precise standard of review that should be applied here.

(see Section II.B., below). Third, the Siting Board requires the applicant to show that its project is viable. 1993 BECo Decision at 15; Enron Power Enterprise Corporation, 23 DOMSC 1, 15 (1991) ("Enron"); MASSPOWER, Inc., 20 DOMSC 301, 310 (1990) ("MASSPOWER"). (see Section II.C., below). Finally, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and (1) in cases where an alternative site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply (See 1993 BECo Decision at 15; New England Power Company, 21 DOMSC 325, 333; NEA, 16 DOMSC at 343), or (2) in cases where a noticed alternative is not required, that the proposed site for the facility will minimize environmental impacts and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply. 1993 BECo Decision at 32; Eastern Energy Corporation, 22 DOMSC 188, at 315-316 ("EEC"); MASSPOWER, 20 DOMSC at 383-404. (see Section III, below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

a. Arguments of the Parties

(1) The Company's Position

The Company argued that, consistent with the statutory mandate and the Court's decision in City of New Bedford, there are two reasonable approaches for the Siting Board to use to determine whether the proposed facility is needed based on reliability considerations -- a demonstration of a capacity deficiency for Massachusetts or a demonstration of a capacity deficiency on a regional basis (Company Second Supplemental Brief at 5-6). The Company asserted that, where a capacity deficiency is demonstrated for Massachusetts based on an analysis of the projected electricity demand within the Commonwealth and the supply resources committed to meet that demand, the clear language of the statute would require the Siting Board to find that a proposed facility is needed to provide a necessary energy supply for the Commonwealth (id.).

In the alternative, the Company asserted that the Siting Board can find need for a proposed facility where a deficiency is demonstrated on a regional basis, provided that the Siting Board provides a statement of reasons why a finding of regional need meets the statutory requirements (id. at 6). Altresco stated that, given the integrated regional electricity system and tangible benefits to Massachusetts resulting from participation in the New England Power Pool ("NEPOOL") system, it would be consistent with the statute to base need for a proposed facility on regional considerations (id. at 6-10).[13]

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[13] The Company asserted that the inextricable link between regional and Massachusetts' reliability and the appropriateness of a regional need analysis was recognized by the Legislature in establishing the Siting Council (Company Second Supplemental Brief at 6-7). The Company asserted that the appropriateness of a regional analysis was also confirmed by G.L. c. 164A, the intent of which is to foster participation of electric utilities in NEPOOL (id. at 8).

In addition, the Company stated that, although the Court was silent on the appropriateness of using economic efficiency[14] as an independent basis to demonstrate need, an economic efficiency analysis also would be consistent with the Siting Board's obligation to ensure a necessary energy supply at the lowest possible cost with a minimum impact on the environment (id. at 10). Therefore, the Company asserted that a demonstration that a proposed facility would result in lower costs for the Commonwealth's ratepayers would be sufficient to establish need (id. at 10-11). The Company further asserted that a regional economic efficiency analysis also would demonstrate Massachusetts' economic efficiency benefits (id.). The Company explained that due to the integrated nature of the NEPOOL system, Massachusetts would share in the economic efficiency savings of a facility, even if the power were sold to a utility outside Massachusetts (id. at 11).

Finally, the Company asserted that regional economic efficiency-based need should be expanded to allow for the determination of need based on a demonstration that the addition of the proposed facility would reduce environmental impacts associated with the generation of electricity to a greater extent than any reductions that would take place without the facility (id. at n.7).

(2) The Intervenor's Position

The Beach Association argued that, in light of the Court's decision in City of New Bedford, the Siting Board must clarify what constitutes a necessary supply of energy for

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14 The Company noted that in Enron, the Siting Council found that economic efficiency can establish need if the addition of the proposed new facility would result in lower generation costs for the system than would be experienced without the new facility (Company Second Supplemental Brief at 10).

The Siting Board notes that in Enron, the Siting Council found that the facility was needed for economic efficiency purposes in addition to reliability purposes. 23 DOMSC at 63-65. The Siting Council made it clear that it would have to evaluate, on a case-by-case basis, whether the magnitude and timing of the economic efficiency gains identified would be adequate to establish need on economic efficiency grounds. Id., 23 DOMSC at 59-60.

reliability purposes, and clarify the difference between necessary, adequate, and sufficient sources of energy for the Commonwealth (Beach Association Supplemental Brief at 23; Beach Association Supplemental Reply Brief at 10). The Beach Association defines the terms: (1) "necessary" as "absolutely needed or required;" (2) "adequate" as "a close meeting of need or barely enough;" and (3) "sufficient" as "enough to meet the needs of a situation or proposed end" (Beach Association Supplemental Brief at 22). The Beach Association stated that, in planning to meet a capacity position in a future year, a necessary supply is one that is needed at a very low confidence level, an adequate supply is one that is needed at a 50 percent confidence level, and a sufficient supply is one that is needed at a very high confidence level (id., at 27).[15]

In discussing planning for future energy supplies, the Beach Association noted that there is a distinction between the reliability of the energy supply, or reliability criterion, in a given year, and the reliability of projections of capacity position in a future year (id. at 27). The Beach Association argued that necessary energy is that which is specifically needed to meet the reliability criterion, but that energy that would increase the probability of meeting the reliability criterion in a future year may or may not be needed, depending on various factors in the future (id. at 30-31). Therefore, the Beach Association stated that, given future uncertainty, energy needed to increase the probability of meeting the reliability criterion in a future year is not necessary energy (id. at 31).

The Beach Association stated that, in the past, in finding that "new capacity is needed where projected future capacity is found to be inadequate to satisfy projected load and reserve requirements," the Siting Council provided for an increase to adequate levels of supply (id. at 24). The Beach Association argued that, instead, the Siting Board should only

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15 The Beach Association maintained that without a necessary supply of energy, Massachusetts will almost surely have an unreliable energy supply in the near future, without an adequate supply of energy, Massachusetts might or might not have a reliable energy supply in the near future and that, with a sufficient supply of energy, Massachusetts will most likely have a reliable energy supply in the near future (Beach Association Supplemental Brief at 22-23).

plan for power that is necessary, given the uncertainties reflected by the various contingencies (id.).[16]

In addition, the Beach Association argued that Altresco's position that need can be established on economic efficiency grounds is inconsistent with the Court's interpretation of the statute that the first consideration must be whether the new energy supply is necessary for the Commonwealth (Beach Association Supplemental Brief at 35; Beach Association Supplemental Reply Brief at 8-9).

b. Analysis

In EEC (Remand), the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with the statutory mandate to implement the energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost and the Court's directive in City of New Bedford. Here, the Siting Board considers the arguments of the Company and the Beach Association in this case to determine if the standard of review set forth in EEC (Remand) continues to be appropriate.[17]

In City of New Bedford, the Court found the Siting Council's finding that New England needed additional energy resources for reliability purposes to be inadequate in light of the statutory mandate that an energy supply must be necessary for the Commonwealth.

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16 The Beach Association maintains that planning to a 50 percent confidence level in the capacity position would mean that power would be unnecessary in half of the cases (Beach Association Supplemental Brief at 24). Therefore, the Beach Association argued that the Siting Council's past practice of planning to a 50 percent confidence level would provide more than a necessary energy supply (id.). The Beach Association stated that the Siting Board should specify the different confidence levels that would provide a necessary energy supply, an adequate energy supply and a sufficient energy supply (Beach Association Supplemental Reply Brief at 12).

17 As noted in Section I, above, the parties had an opportunity to address the ruling in City of New Bedford on the issue of need and did so through the filing of additional testimony, discovery, cross-examination at hearings, and by filing additional briefs on the issue.

413 Mass. at 489. In addition, the Court noted that, although the Siting Council had argued that its mandate was to ensure an adequate energy supply at minimum cost, "[e]nsuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth' (emphasis added)." Id., 413 Mass. at 490, citing, G.L. c. 164, § 69H.

First, with respect to the issue of an adequate versus a necessary energy supply, the Siting Board disagrees with the Beach Association's distinction between the terms necessary and adequate. After reviewing the legislative history and possible definitions of the terms in EEC (Remand), the Siting Board found that it would be appropriate, without more specific guidance from the Court regarding the definitions of necessary and adequate, to adopt the Siting Council's past approaches to determining whether the addition of a proposed facility to the energy supply is necessary (at 178-181).[18] The Siting Board noted that need has been found: (1) where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements; (2) in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs; or (3)

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18 Before making this finding, the Siting Board stated that:

> "[a] necessary energy supply is one that would be capable of meeting demand in situations that are likely to occur. Thus, a necessary energy supply would be capable of meeting forecasted peak-day demand and would include a (reserve) margin to account for the likelihood of power generating facilities not being available (either planned or unplanned) on those peak days....
>
> As transmission systems are not 100 percent efficient in transporting electricity, additional amounts of electric power are necessary to account for these losses, losses that can increase as the distance between the power generation site and its end-use increases. (footnote omitted) Therefore, to provide for the interests of consumers, any definition of necessary energy supply should allow for consideration of these transmission factors.
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> Further, as G.L. c. 164 requires a necessary energy supply to be provided with a minimum impact on the environment at the lowest possible cost, it is reasonable to conclude that a proposed facility may be necessary even if there is no additional need for supply capacity or transmission reasons. In such a case, an applicant would have to establish a record that supported a finding by the Siting Board that the Commonwealth's energy supply would have lower costs and/or reduced environmental impacts with the addition of the proposed facility than it would have without the addition of the proposed facility." (footnotes omitted). EEC (Remand) at 180-181.

principally for providing economic energy supplies relative to a system without the proposed facility. EEC (Remand) at 181; EEC, 22 DOMSC at 203-205.

With respect to the issue of regional need vs. Massachusetts need, the Court, in City of New Bedford, stated that our statutory mandate is to ensure that a necessary energy supply is provided for the Commonwealth and further stated that a finding of regional need is inadequate as the sole foundation of a finding of need for additional energy resources for the Commonwealth. Nevertheless, given the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability, and recognizing the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration, the Siting Board has stated that consideration of regional need is a central part of any need analysis for a power project not yet linked to individual utilities by PPAs. See EEC (Remand) at 185. The Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A. This same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3,4. A review of need that is limited to the need in the Commonwealth for new energy resources would require the construct of an electric energy market that was limited by state borders and would appear to be contrary to legislative intent. EEC (Remand) at 186. Accordingly, the Siting Board has found that an analysis of regional need must form the foundation for an analysis of Massachusetts need. Id.

The Company argued that a showing of a Massachusetts capacity deficiency or a regional capacity deficiency should be sufficient, on its own, to establish need for a proposed facility. As stated above, the Siting Board recognizes that a regional capacity analysis provides a necessary foundation for, rather than the sole determinant of, a finding of need.

Therefore, neither a regional capacity deficiency, taken alone, nor a Massachusetts capacity deficiency, taken alone, would be sufficient to establish need. Id. at 188.[19]

Finally, with respect to the issue of establishing need on economic efficiency grounds, the Siting Board agrees with the Company that an economic efficiency analysis of need would be consistent with our statutory obligation 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, §§ 69H, 69J. The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. EEC (Remand) at 186-187. However, in response to the Court's reminder in City of New Bedford that our statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in EEC (Remand) that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need. Id. at 187.

After considering the arguments presented by the company and the Beach Association, the Siting Board concludes that the standard of review for the determination of need established in EEC (Remand) continues to be appropriate. That standard is set forth below.

c. Conclusion

In conclusion, in accordance with G.L. c. 164, § 69H, the Siting Board is charged with the responsibility for implementing energy policies to provide a necessary energy supply

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19 The Siting Board has also found that demonstration of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply. See, EEC (Remand) at 188. The Siting Board noted that an applicant could establish that reliance on a regional surplus to address or offset a Massachusetts supply deficiency could involve transmission or other reliability constraints or could be contrary to the statutory mandate to ensure that a necessary energy supply is provided for the Commonwealth at the lowest possible cost with least environmental impact. Id.

for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Board, therefore, must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities. With respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources to meet reliability, economic, or environmental objectives directly related to the energy supply of the Commonwealth.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate 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 Board may find 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. EEC (Remand) at 190-191; 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 Board may find 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. EEC (Remand), at 191; Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. EEC (Remand), at 191.

While G.L. c. 164, § 69H, requires the Siting Board to ensure a necessary supply of energy for Massachusetts, the Siting Board interprets this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources,[20] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. EEC (Remand), at 191; Turners Falls Limited Partnership, 18 DOMSC 141, 151-165 (1988); Massachusetts Electric

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20 See, Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985); Boston Edison Company, 13 DOMSC 63, 70-73 (1985).

Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985). In doing so, the Siting Board fulfills the requirements of G.L. c. 164, § 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 Board requires the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. EEC (Remand) at 192. 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, the need for additional energy resources must be established through an analysis of regional capacity and a showing of Massachusetts need based either on reliability, economic or environmental grounds directly related to the energy supply of the Commonwealth. Id.

2. 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 a 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 for the need for additional energy resources for reliability purposes. Id.

Here, Altresco has a signed and approved PPA for 25 MW -- 14.7 percent of plant output -- of capacity and related energy with ComElectric (Exh. HO-MB-12S).[21] In addition, the Company stated it was designated the sole award winner of BECo's RFP 3 on June 1, 1992, for 132 MW (Exh. HO-RR-30). Therefore, the Company asserted that it has demonstrated Massachusetts need for the project for both economic efficiency and reliability purposes (Company Initial Brief at 63).

The Siting Board notes that the Company has established that the ratepayers of ComElectric are likely to receive economic efficiency and reliability benefits from the proposed additional power resources. However, the Siting Board also notes that the signed PPA with ComElectric constitutes only 14.7 percent of the capacity output of the proposed project. In a recent review, the Siting Board determined that 75 percent of total output sold would be sufficient to establish need for the proposed project. EEC (Remand) at 268.

In regard to BECo's RFP 3 solicitation, however, the Siting Board notes that a petitioner's inclusion in an award group does represent an important first step toward reaching approved PPA status. See West Lynn Cogeneration, 22 DOMSC 1, 39 (1991) ("West Lynn"); MASSPOWER, 20 DOMSC at 326-327. However, there currently exists uncertainty as to if, and when, the PPA will be signed between Altresco and BECo because of a pending appeal concerning the RFP 3 solicitation (See n.3, above). Further, the standard of review requires signed and approved PPAs to establish need on economic efficiency or reliability grounds.

Accordingly, based on the foregoing, the Siting Board finds that Altresco has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPAs. Therefore, the Siting Board reviews

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21 The Company notes that executed contracts between Altresco and ComElectric and Cambridge Electric Light Department were filed with the Department on November 27, 1991, concerning a proposed settlement of RFP #2 issues for both the Altresco facilities in Lynn and Pittsfield facilities (Exh. HO-MB-1). The Company presented documentation from the Department approving the power purchase agreement between Altresco and ComElectric on March 18, 1992 (Exh. HO-MB-12S).

the Altresco analysis of regional and Massachusetts need to determine if the proposed project is needed to provide necessary energy to the Commonwealth.

3. New England's Need

a. Introduction

Altresco asserted that there is a need for 170 MW in New England beginning during the time period of 1995 to 1997 and beyond (Company Initial Brief at 13, citing, Tr. 9 at 121-122). In support, the Company (1) presented a series of forecasts of demand and supply for the region, based, in part, on data and 1992 forecasts published by NEPOOL, and (2) combined demand and supply forecasts to produce a series of need forecasts (Exh. AL-13).[22] Altresco asserted that it provided a comprehensive analysis of the need for the proposed facility, consistent with Siting Council standards (Company Initial Brief at 14). Altresco also presented an analysis of regional need based on economic efficiency grounds (Exhs. HO-N-38S; HO-RR-58; HO-RR-60A). The Company asserted that this analysis establishes need for the project on economic efficiency grounds (Company Initial Brief at 52).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of Demand Side Management ("DSM") savings over the forecast period, and the supply forecasts provided by

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[22] Altresco originally provided an analysis of regional need based, in part, on load forecast data contained in the NEPOOL Forecast of Capacity, Energy, Loads and Transmission ("CELT Report") 1990-2005 ("1990 CELT Report") and the CELT Report 1991-2006 ("1991 CELT Report") (Exhs. AL-2, sec. 9; AL-12, at 1 to 15). In its original analysis, the Company subjected its need forecasts to a variety of contingency tests to evaluate the sensitivity of the need projections to the uncertainty inherent in the underlying forecast assumptions (Exhs. AL-2, at 9-18 to 9-30; AL-3, exhs. 9-L, 9-O).

The Company updated its analysis of regional need after the publication of the CELT Report 1992-2007 ("1992 CELT Report") (Exh. AL-13). In its updated analysis of regional need, the Company did not provide an updated analysis of contingency scenarios (id.).

the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts, which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the Company's analysis of economic efficiency need.

b. Demand Forecasts

Altresco presented eleven demand forecasts of adjusted peak load demand (Exh. AL-13). The Company stated that it based its demand forecasts on seven different demand forecast methodologies and two different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 2-20, 23-24). To derive its eleven demand forecasts, the Company indicated that it adjusted results from four of its forecast methodologies to reflect the two respective DSM forecasts (id., attach. RLC-26). The Company utilized the results from the remaining three forecast methodologies without separate reductions to reflect DSM (id.).

(1) Description of Demand Forecast Methodologies

The Company stated that it developed four demand forecasts based on load forecast data contained in the 1992 CELT Report and three additional demand forecasts based on historical trends (id. at 1-16).[23] With respect to the 1992 CELT Report-based forecasts, Altresco noted that the 1992 CELT Report contains three distinct forecasts of regional load -- a high demand forecast, a reference forecast, and a low demand forecast (id. at 1-2).[24]

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23 In its updated regional need analysis, the Company included an analysis of need based on the 1990 and 1991 CELT Reports for illustrative purposes but not for the purpose of evaluating regional need (Exh. AL-13, at 23-24). For purposes of this review, the Siting Board does not consider the 1990 or 1991 CELT Report or associated need analyses in the analysis of need for the proposed facility.

24 Altresco indicated that NEPOOL characterizes: (1) the high demand case as having a 10 percent probability of being exceeded; (2) the reference case as having a fifty percent probability of being exceeded; and (3) the low demand case as having a 90 percent probability of being exceeded (Exh. AL-13, at 1-2).

The Company stated that it utilized the reference forecast and high demand forecast and based two additional forecasts on variations of the 1992 CELT Report forecasts, including (1) the arithmetic average of the 1992 CELT Report high and low demand cases ("high-low average forecast"), and (2) a linear projection between 1992, or first year, reference forecast peak load and 2007, or end-year, reference forecast peak load ("end-year linear forecast") (id. at 1-16, 23-24).

With respect to the forecasts based on historical trends, the Company stated that it developed three forecasts as follows: (1) a historical time series constant annual growth rate ("CAGR") regression forecast, based on projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("CAGR regression forecast"); (2) a historical time series linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("linear regression forecast");[25] and (3) a multiple regression forecast based on the 1974-1989 multiple regression relationship of personal income and time to peak load, and a forecast of personal income ("multiple regression forecast") (id. at 9-16; Exh. HO-N-4).[26]

The Company indicated that three of the seven forecast methodologies -- the reference forecast, the CAGR regression forecast, and the linear regression forecast -- are common to both the regional need analysis and the Massachusetts need analysis (Exh. JH-RR-7; Tr. JH2, at 49-51).

The Company asserted that the high-low average forecast, the end-year linear forecast, the CAGR regression forecast, the linear regression forecast, and the multiple regression

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25 The Company noted that the CAGR regression forecast and linear regression forecast were updated to reflect 1992 CELT Report data (Exh. AL-13, at 2).

26 The Company indicated that the forecast of personal income for the years 1990-2014 was based on a forecast for Massachusetts from the Massachusetts Division of Energy Resources ("DOER") which in turn was based on a forecast produced by Regional Economic Models Inc. ("REMI") (Exh. AL-13, at 13). The Company further indicated that the DOER forecast extended only through 1996 and that the forecast was extended through 2007 by assuming a CAGR for the 1997-2007 period equal to the CAGR for the 1992-1996 period that was included in the DOER forecast (id.).

forecast reflected reliable methodologies to forecast the regional demand for power (Company Initial Brief at 15). However, the Company stated that it considered the high-low average forecast to represent a principal demand forecast and the end-year linear forecast to represent a conservative but reasonable alternative (Exh. AL-13, at 16).[27]

(a) 1992 CELT Report Forecasts

As noted above, the 1992 CELT Report contains a high demand forecast, a reference forecast, and a low demand forecast (id. at 1-2). With respect to the reference forecast, Altresco asserted that such a forecast was not appropriate, without adjustment, for use in the regional need analysis (Company Initial Brief at 23). In explaining NEPOOL development of the reference forecast, the Company provided the NEPOOL Forecast of New England Electric Energy and Peak Load Executive Summary 1992-2007 ("Executive Summary") which indicated that NEPOOL produced (1) a short-term forecast for the years 1992 and 1993 based on an econometric model of three exogenous variables, personal income, number of residential customers, and real energy prices, and (2) a long-term forecast for the years 1996 through 2007 based on an end-use model (Exh. HO-RR-38(c) at 2-1). The Executive Summary indicated that NEPOOL then merged the short-term and long-term forecasts to produce projections for the years 1994 and 1995 and that, in moving from the short-term to long-term, "the forecast was adjusted to approach the long-run results smoothly over a two year interim period" (id.).

Altresco characterized the reference forecast as a reasonable low demand case (Exh. AL-13, at 7). Altresco stated that the reference forecast reflects a CAGR in adjusted peak load of only 0.56 percent over the 1992-1995 period[28] and projects that adjusted peak

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27 Mr. La Capra indicated that both the high-low average forecast and end year linear forecast meet the criterion established by the Siting Council in Enron and EEC that a principal demand forecast be based on a sophisticated methodology (Exh. AL-13, at 13-16).

28 The Siting Board notes that the reference forecast annual growth in load for the period (continued...)

load will be lower than NEPOOL's 1991 weather-normalized summer peak of 19,700 MW until the year 1994 (id. at 3, 8).[29] The Company asserted that the New England region is currently experiencing an economic recovery and that the lack of short-term growth in peak demand projected by the reference forecast is inconsistent with the region's historical experience in emerging from recessions (id. at 8; Exh. HO-RR-76).[30]

Mr. La Capra maintained that the downward bias of the short-run results of the reference forecast results, primarily, from (1) overly pessimistic economic assumptions which underlie the personal income forecast, and (2) unrealistically high fuel price projections which are the primary drivers of real electricity prices (Exh. AL-13, at 8; Tr. 11, at 4 to 9). In forecasting the variables underlying the short-term forecast, Mr. La Capra explained that NEPOOL relied on a modified Delphi method, or opinion poll of members of its Load Forecasting Committee (Exh. HO-RR-38(c) at 2-1; Tr. 11, at 8). He noted that NEPOOL adjusted the personal income forecast for 1992 downward from an objective forecast of personal income in order to lower the short-term forecast (Tr. 11, at 74-78).[31] He also

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[28](...continued)
1991-2000 is as follows: (1) 1992, -1.06 percent; (2) 1993, 0.51 percent; (3) 1994, 1.44 percent; (4) 1995, 1.39 percent; (5) 1996, 2.52 percent; (6) 1997, 1.4 percent; (7) 1998, 2.7 percent; (8) 1999, 2.8 percent and (9) 2000, 1.96 percent (Exh. HO-RR-61, at 1).

[29] Mr. La Capra indicated that the reference forecast, adjusted by the 1992 CELT values for DSM reflects a CAGR in adjusted peak load of: (1) 1.9 percent over the 1991-2007 forecast period; (2) 0.56 over the 1991-1995 period; (3) 2.3 percent over the 1995-2000 period; and (4) 2.4 percent over the 2000-2007 period, (Exh. AL-13, at 3). Mr. La Capra noted that the CAGR of the reference forecast is nearly equal to that of the high demand forecast over the 2000-2007 period (id.).

[30] Altresco stated that NEPOOL's short-term forecast assumes recovery will not begin until the fourth quarter of 1992 whereas recent economic indicators demonstrate that the region's recovery began in the first quarter of 1992 (Exh. HO-RR-76; Tr. 11, at 4).

[31] Mr. La Capra indicated that the "NEPOOL Economic and Demographic Forecast, New England and the Six States, 1992-2007" ("1992 Economic and Demographic (continued...)

noted that NEPOOL made upward adjustments to an objective forecast of residual oil and natural gas fuel price escalators (Exh. HO-RR-59).[32,33]

The Company asserted that, although the methodological flaws in the reference forecast pertain largely to the short-term forecast, the short-term forecast directly impacts the growth in demand projected by the long-term forecast for the year 1996 and beyond (Company Initial Brief at 30-37). Mr. La Capra explained that the short-term forecast causes the long-term forecast to begin from a lower base and therefore produces a significantly

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[31](...continued)
Forecast") specifies an increase in real personal income of 1.9 percent in 1991 and 2.2 percent in 1992 whereas a zero percentage increase for 1991 was assumed by NEPOOL in the short-term forecast (Exh. HO-RR-75, at 13; Tr. 11, at 77). The 1992 Economic and Demographic Forecast For New England was the sum of the six state forecasts which in turn were based on the New England Power Planning Committee ("NEPLAN") state-specific economic models developed from REMI state models and the 1991 Data Resources Inc. ("DRI") national economic forecast (Exh. HO-RR-75, at 1).

[32] Mr. La Capra indicated that the NEPOOL fuel price forecast was derived from the draft December 1991 NEPOOL "Summary of the Generation Task Force Long-Range Study Assumptions" ("GTF") which, in turn, was based on an October 1991 DRI energy forecast ("1991 DRI forecast") (Exh. HO-RR-59). However, he noted that the residual oil and natural gas price escalators used by NEPOOL for the 1992-1994 period were significantly higher than the comparable fuel price escalators included in the 1991 DRI forecast (id.). Further, Mr. La Capra noted that the fuel prices included in the 1992 GTF, with the exception of nuclear fuel, were lower than those prices projected by NEPOOL in the 1992 CELT Report (id.).

[33] In order to approximate the impacts that a change in NEPOOL's fuel price would have on its projections of regional demand, the Company provided alternative forecasts based on lower fuel price assumptions included in (1) the 1992 GTF, and (2) the May 1991 forecast of fuel prices prepared for a New England utility (Exh. HO-RR-77). The Company provided an additional demand forecast based on the United States Department of Energy ("DOE") annual electricity sales projections for New England (id.). The Company stated that all three forecasts would show need for the proposed project earlier than the reference forecast (id.).

lower forecast of peak load (Tr. 11, at 71).[34] The Company asserted that further evidence of the influence of the short-term forecast on the long-term forecast is the dramatic difference in the slope of the forecast for the 1991-1995 period (0.56 percent) and 1995-2000 period (2.29 percent) (Company Initial Brief at 31).[35]

In sum, the Company asserted that the reference forecast should be rejected for the same reasons that the Siting Council previously rejected the 1991 CELT forecast -- inconsistency with historical trends, overly pessimistic economic assumptions and inflated oil prices (Company Initial Brief at 34-37).[36]

With respect to the high and low demand forecasts in the 1992 CELT Report, Mr. La Capra characterized the high demand forecast as a reasonable high demand case to be included in the Company's analysis of regional need (Exh. AL-13, at 7, 23). He indicated that the high demand forecast anticipates a spurt in the demand for electricity based on a strong recovery of the regional economy and sustained strong growth in peak demand

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34 The Company further explained that because NEPOOL fuel price forecasts are expressed as annual escalation rates rather than absolute dollar values, the effects of the fuel price escalators assumed by NEPOOL for 1992 continue through the forecast period and are compounded by the high price elasticity assumed by NEPOOL (Exh. HO-RR-59). The Company asserted that the annual escalation rates would cause the long-run demand forecast to begin from a lower base point because the annual fuel price escalation rates are applied to a base value, specifically the fuel price in the 1995 forecast, which is greatly influenced by the short-term forecast (Company Initial Brief at 31; Tr. 11, at 70-71).

35 The Company asserted that, assuming the 1996 forecast was produced solely by the long-run model, the long-run model would therefore have independently forecasted the same 0.56 percent growth rate for the 1991-1995 period, contradicting economic assumptions underlying the forecast (Company Initial Brief at 31, citing, Exh. HO-RR-75, at 13). In addition, the Company asserted that there is no evidence of a sufficiently large adjustment in the years 1994 and 1995 to bridge the gap between the load growth slopes of 0.56 percent and 2.29 percent (id.).

36 See Enron, 23 DOMSC at 42-43; EEC, 22 DOMSC at 235-236.

throughout the forecast period (id. at 7).[37] He stated that although such economic assumptions would be consistent with the region's repeated pattern of higher than average recovery from a recessionary period, he considered the magnitude of the projected growth spurt and CAGR over the forecast period to be optimistic (Exh. AL-13, at 7-8; Tr. 9, at 103).

Mr. La Capra indicated that the low demand forecast in the 1992 CELT Report predicts a significant decline in peak demand in 1992, remaining below the NEPOOL 1991 weather-normalized summer peak until the year 2000 (Exh. AL-13, at 9). He stated that such a decline in peak demand is unprecedented and unsupported by evidence that an economic recovery is currently underway (id.). He, therefore, characterized the low demand forecast as having a probability of occurrence of essentially zero and stated that it should be discarded from the analysis of regional need (id.).

(b) High-Low Average Forecast

As noted above, the Company indicated that the high-low average forecast, the arithmetic average of the low demand forecast and the high demand forecast from the 1992 CELT Report, represents its principal forecast.[38] Given that the reference forecast is significantly closer to the low demand forecast than the high demand forecast, Mr. La Capra indicated that the high-low average forecast would better represent the range of forecasts embodied in the 1992 CELT Report than would the reference forecast (Exh. AL-13, at 12-

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[37] Mr. La Capra indicated that the 1992 CELT Report high demand forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 3.4 percent over the 1991-2007 forecast period; (2) 5.0 percent over the 1991-1995 period; (3) 3.5 percent over the 1995-2000 period; and (4) 2.5 percent over the 2000-2007 period (Exh. AL-13, at 2-3).

[38] Mr. La Capra indicated that the high-low average forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 2.15 percent over the 1991-2007 forecast period; (2) 2.12 percent over the 1991-1995 period; (3) 2.37 percent over the 1995-2000 period and (4) 2.01 percent over the 2000-2007 period (Exh. AL-13, attach. RLC-16).

13, 16).[39] However, he added that, in assuming equal probability for the low demand forecast and high demand forecast, the high-low average forecast constitutes a conservative projection of future load growth (Exh. HO-RR-65).[40] He noted that the high-low average forecast shows stronger growth in the early years relative to the reference forecast (Tr. 9, at 65).

The Company asserted that the 1992 NEPOOL Resource Adequacy Assessment, Technical Supplement ("Resource Assessment") confirms that the high-low average forecast is a reasonable forecast (Company Initial Brief at 38). The Resource Assessment provides a probability distribution for the variation in expected regional load growth assumed by NEPOOL for the years 1993 through 1997 (Exh. HO-RR-77(h)). From this distribution, the Resource Assessment provides the expected value, or weighted average of all possible outcomes in the distribution, of the load forecast for each year from 1993 though 1997 (id.). Mr. La Capra noted that the expected value of the 1997 capacity position is reasonably close to the 1997 capacity position projected by the high-low average forecast (Exh. HO-RR-77; Tr. JH-1, at 17).[41] Mr. La Capra further noted that the Resource Assessment demonstrates that the uncertainty associated with load growth, existing utility attrition, DSM and other factors is more likely to result in a capacity shortfall than a capacity surplus if NEPOOL plans its resources to meet the reference forecast (Exh. HO-RR-77).

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39 The Company stated that this asymmetry means there is a greater likelihood of the reference forecast underforecasting than overforecasting demand by a given margin (Exh. AL-13, at 12).

40 As noted above, the Company considers the high demand forecast to be a reasonable high demand case while it considers the low demand forecast to have a probability of occurrence of essentially zero (Exh. AL-13, at 7).

41 The Company indicated that the expected value in 1997 is a capacity deficiency of 241 MW (Exh. HO-RR-77). The Siting Board notes that, assuming the Company's base supply forecast, the high-low average forecast projects a 1997 capacity deficiency ranging from 961 MW to 1356 MW, under two alternative DSM forecasts (Exh. AL-13, exh. attach. RLC-26).

(c) End-Year Linear Forecast

With respect to the end-year linear forecast, the Company explained that this forecast assumes that the beginning and end points of the reference forecast are correct and that peak load will grow linearly between these two points (id. at 11). The Company stated that, therefore, the end-year linear forecast partially corrects for the unreasonable assumptions underlying short-term growth in the reference forecast (Exh. AL-13, at 11-12).[42] The Company noted that, in reflecting the same long-term increase as the reference forecast -- 1.9 percent per year between 1992 and 2007 -- the end-year linear forecast is reasonable but conservative relative to other forecasts based on the region's long-term trends (id.).[43]

(d) Forecasts Based on Historical Trends

As noted above, the Company provided three additional demand forecasts based on historical trends -- the CAGR regression forecast, the linear regression forecast and the multiple regression forecast. The Company stated that it developed the CAGR regression forecast and linear regression forecast based on performing time series regression analysis of 1974-1991 weather-normalized summer peak load data for New England derived from NEPOOL data (id. at 10; Exh. AL-12, at 5-7). The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the regression equations, and claimed that a moderate-to-high amount of DSM thus was incorporated in the regression forecasts (Exh. HO-MN-4).[44] The Company stated that the projected growth in peak load

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42 Mr. La Capra indicated that the end-year linear forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 1.90 percent over the 1997-2007 forecast period; (2) 2.13 over the 1991-1995 period; (3) 1.95 percent over the 1995-2000 period, and (4) 1.74 percent over the 2000-2007 period (Exh. AL-13, attach. RLC-16).

43 The Company indicated that the projected growth in peak load would be 433.6 MW per year under the end-year linear forecast (Exh. HO-RR-65).

44 The Company stated that the regression forecasts reflect a continuation of a rapid rate of increase in DSM resources over the historical period and that the rate of growth in (continued...)

would be 2.93 percent per year under the CAGR regression forecast and 468 MW per year under the linear regression forecast (Exh. AL-13, attachs. RLC-16, RLC-17b).[45] The Company stated that, although each of the regression formats exhibits statistically solid results, the CAGR regression forecast is statistically superior (id. at 10).[46]

The Company stated that it developed the multiple regression forecast using personal income and time as independent variables (id. at 13-14).[47,48] Mr. La Capra acknowledged that the confidence in this forecast methodology depends on the forecast of personal income and stated that the forecast of personal income utilized in developing the multiple regression forecast was reliable (Exh. HO-RR-74; Tr. 10, at 106).[49] Mr. La Capra asserted that,

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[44](...continued)
DSM resources is likely to decline over time as cost-effective DSM opportunities decline (Exh. MN-4). Therefore, the Company stated that the DSM included in the regression forecasts is likely to be accurate in the short-run but too high in the long-run (id.).

45 Mr. La Capra indicated that the linear regression forecast, reflects a CAGR in adjusted peak load of: (1) 2.00 percent over the 1991-2007 forecast period; (2) 2.25 percent over the 1991-1995 period; (3) 2.05 percent over the 1995-2000 period, and (4) 1.82 percent over the 2000-2007 period (Exh. AL-13, attach. RLC-16).

46 The Company noted that the use of a CAGR regression was accepted by the Siting Council in Enron, EEC, and West Lynn (Company Reply Brief at 4).

47 Mr. La Capra indicated that a series of single and multiple regression analyses of three independent variables -- time, Massachusetts personal income and Massachusetts state product -- demonstrated that the regression on personal income and time exhibited the best overall statistical results (Exh. AL-13, at 13-14).

48 Mr. La Capra indicated that the multiple regression forecast reflects a CAGR in adjusted peak load of: (1) 3.00 percent over the 1991-2007 forecast period; (2) 2.96 percent over the 1991-1995 period; (3) 3.00 percent over the 1995-2000, period and (4) 3.03 percent over the 2000-2007 period (Exh. AL-13, attach. RLC-16).

49 Altresco asserted that the economic forecast underlying the multiple regression forecast is more reliable than the economic forecast underlying the reference forecast because (1) it is more recent; (2) it was not adjusted by the modified Delphi method; and (3) it is supported by recent economic data and projections from numerous forecasters (Company Reply Brief at 5, citing, Exhs. HO-RR-62; HO-RR-76).

absent major structural changes in the economy such that increases in disposable income and commercial activity would not require increases in energy use, the multiple regression forecast would be the best predictor of electric demand over the long-term (Tr. 10 at 102-106).

(2) Arguments of the Parties

The Beach Association took issue with the Company's economic assumptions and demand forecast methodologies (Beach Association Initial Brief at 2-5; Beach Association Reply Brief at 2-9). The Beach Association argued that the recession was not limited to the 1990-1991 time frame as suggested by the Company, but instead, continues (Beach Association Initial Brief at 2,5). Thus, the Beach Association maintained that the reference forecast and the low demand forecast would likely be accurate forecasts for the short-run (id. at 6).[50] The Beach Association added that this recession is unlike previous recessions (Beach Association Reply Brief at 4).

With respect to the Company's demand forecast methodologies, the Beach Association argued that the CAGR regression forecast should be excluded from the analysis of need because it is not "a proper model during a recession" (Beach Association Initial Brief at 2; Beach Association Reply Brief at 2-3). The Beach Association stated that the CAGR of peak load for the 1974-1989 period would differ from the CAGR of peak load for the 1974-1998 period due to the continuing recession and the likelihood that the recovery from the current recession will be weaker than previous recoveries (Beach Association Reply Brief at 2-3).[51]

The Beach Association argued that the multiple regression forecast also should be

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50 The Beach Association argued that the fuel price assumptions of the 1992 CELT Report are as reasonable as the alternative assumptions presented by the Company (Beach Association Initial Brief at 6).

51 Altresco responded that the CAGR regression forecast demonstrates the long-term trend in the region's demand for electricity in that it was based on historical growth in demand over a period which included multiple recessions and recoveries (Company Reply Brief at 3).

excluded from the analysis of need (Beach Association Initial Brief at 2). In support, the Beach Association stated that economic activity cannot be predicted with certainty and the Company's assumption of the time frame of the current recession in that forecast is speculative (id.).

Finally, the Beach Association objected to the use of the high-low average forecast as the base forecast and argued that this forecast would be unacceptable even as an alternative forecast (id., at 3-4; Beach Association Reply Brief at 5-9). The Beach Association stated that the high-low average forecast is not based on a sophisticated methodology and is essentially a modification of the CAGR regression forecast (Beach Association Reply Brief at 8). The Beach Association added that the Company asserted that the high demand forecast and low demand forecast were not equally probable and, therefore, the average of the two forecasts was not a valid method to determine the center of the distribution (id. at 7; Beach Association Initial Brief at 3).[52]

(3) Analysis

As noted above, the Company presented two demand forecasts included in the 1992 CELT report (the reference forecast and the high demand forecast), developed two additional demand forecasts based on the load forecast data contained in the 1992 CELT report (the end-year linear forecast and the high-low average forecast) and developed three additional demand forecasts based on historical trends (the linear regression forecast, the CAGR regression forecast and the multiple regression forecast).

With respect to the reference forecast, the Siting Board notes that the CELT report has previously been acknowledged as an appropriate starting point for resource planning in New England and CELT forecasts have previously been accepted for the purposes of evaluating regional need in reviews of proposed non-utility generator ("NUG") facilities. See, EEC

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52 Altresco responded that the high-low average forecast assumption of equal probability of the high demand forecast and low demand forecast is not cause to reject the forecast and that the forecast does not produce a constant growth rate (Company Reply Brief at 6).

(Remand) at 211; Enron, 23 DOMSC at 42; EEC, 22 DOMSC 234-236; NEA, 16 DOMSC at 354. Specifically, the reference forecast has been accepted by the Siting Board as an appropriate base case forecast for use in the analysis of regional need.[53] See, EEC (Remand) at 211.

Here, the Company characterized the reference forecast as overly pessimistic, particularly in the near term, and argued that it should be rejected from the analysis of regional need. As noted above, the Company argued that overly pessimistic economic trends, and high fuel price projections dampened the short-term forecast for the years 1992 and 1993 which, in turn, affected the growth in demand projected by the long-term model for the years 1996 and beyond.

In merging the short-term and long-term forecasts, NEPOOL stated in the 1992 CELT Report that it "adjusted the forecast to approach the long-run results smoothly over a two year interim period" (Exh. HO-RR-38(c) at 2-1). The Company raised significant concerns relating to NEPOOL's adjustment of the forecast in the interim period, citing the low CAGR of 0.56 percent over the 1991-1995 period as compared to the CAGR of 2.29 percent over the 1995-2000 period. The CAGR over the 1991-1995 period reflects the lack of growth between 1991 and 1992 (-1.06 percent) and minimal growth between 1992 and 1993 (0.51 percent).

However, given that the first year of reliance on the long-term forecast is 1996, the reason for the Company's emphasis on relative trends over the 1991-1995 period and 1995-2000 period is unclear.[54] An examination of the average annual increase in growth over the

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53 In previous reviews, the Siting Council also stated its concerns with the 1991 CELT forecast that compromised the validity of the forecast, and, therefore, found that need cases developed from the 1991 CELT forecast should not be used for the purposes of evaluating regional need. See Enron, 23 DOMSC at 42-43; EEC, 22 DOMSC at 235-236.

54 The Company's comparison appears to assume that the 2.52 percent increase between 1995 and 1996 is a direct output of the long-term forecast, rather than simply a reflection of the difference between 1995 peak load, which is not part of the output of (continued...)

1991-1996 period, including the transition period, from 1993 to 1996, shows increases in demand significantly larger than the four-year average of 0.56 percent cited by the Company. Specifically, the average annual growth in demand is 0.95 percent for the overall 1991-1996 period and 1.78 percent for the transition period between 1993 and 1996.[55] Further, the growth in demand over the 1996-2000 period is 2.24 percent, less than that over the 1995-2000 period. Thus, although the Company questioned the short-term forecast of growth rate between 1991 and 1993, the rate of growth assumed between 1993 and 1996 is significantly higher. Thus, it is not clear that the low peak load projections for 1992 and 1993 had a significant impact on the long-term forecast. In addition, regarding the Company's arguments that economic indicators show a recovery is already underway, the Siting Board notes that peak load would not necessarily respond immediately to changes in economic indicators.

In sum, the record does not demonstrate that, for the forecast years beyond 1995, the reference forecast is obviously biased, either upward or downward, such as to lead the Siting Board to question the validity of the forecast for those years. Further, the reference forecast has a wide level of recognition for capacity planning purposes in the New England region and has been incorporated directly into Altresco's analysis without the need for adaptation by the proponent. Thus, the Siting Board finds that the reference forecast is an appropriate base case forecast for use in the analysis of regional demand for the years 1996 through 2007.[56]

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[54](...continued)
the long-term forecast, and 1996 peak load, which is within the time frame of reliance on the long term forecast. There is no evidence to support an interpretation that the long-term forecast method produces results in the form of percentage changes in peak load.

[55] The annual transition period increases are 1.44 percent between 1993 and 1994, 1.39 percent between 1994 and 1995, and 2.52 percent between 1995 and 1996.

[56] As noted above, Altresco considers the high demand forecast to represent a reasonable high demand case. However, given that NEPOOL characterizes the forecast as having only a ten percent chance of occurring, the Siting Board considers the high demand forecast to represent a sensitivity analysis of varying economic assumptions rather than (continued...)

With respect to the high-low average forecast, the Company notes that the average of NEPOOL's high and low forecast is higher than the 50 percent confidence level, or median level, reflected in the reference forecast. The Company also claims that the high-low forecast produced a 1997 capacity position result that is comparable to that shown in the 1992 Resource Assessment's expected value forecast.

The Siting Board notes that, in producing forecast results that are greater than the 50 percent confidence level reflected in the reference forecast as a result of high side uncertainty, the high-low average forecast is conceptually akin to NEPOOL's expected value forecast. In EEC (Remand) at 212-213, the Siting Board stated that in order to accept an expected value forecast as a base case forecast, a proponent would be required to provide a cost/benefit analysis to support planning to a higher reliability level. Absent such an analysis, the Siting Board found in that review that an expected value forecast was acceptable for use in an analysis of regional need, but not as a base case forecast. Id.

Here, in proposing the high-low average forecast as a base case forecast, the proponent has not addressed the cost of planning to a reliability level greater than fifty percent. Accordingly, based on the foregoing, the Siting Board finds that the high-low average forecast is an acceptable forecast for use in an analysis of regional need, but does not constitute a base case forecast.

With respect to the end-year linear forecast, Altresco argued that the long-term linear trend would dampen the short-term pessimism of the reference forecast. However the Company did not explain its reasons for choosing a linear format, in particular, to develop a long-term trend, or its reasons for using the end year alone as the basis for determining the slope of the linear trend.

The Siting Board notes that the Company's end-year linear forecast shows higher peak load than the reference forecast for the entire 15-year span of the forecast period, excepting the end year itself. Further, the reference forecast shows its most rapid growth over the

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[56](...continued)
a forecast of regional demand. Thus, the Siting Board does not include the high demand forecast in its analysis of regional need.

latter ten years of the forecast period -- with annual increases in peak load ranging from 434 MW to 672 MW. Thus, the end-year linear forecast is potentially sensitive to the Company's choice of a representative long-term forecast year for purposes of developing the linear trend. While we recognize the intuitive logic of using the end year to represent the long term, Altresco might have provided a more balanced basis to develop the long term trend of its forecast if it had used a range of later years in the forecast, rather than just the end year. In addition, Altresco might have provided a clearer rationale for its selection of a linear long-term trend format as part of the end-year forecast approach.

Accordingly, based on the foregoing, the Siting Board finds that the end-year linear forecast is an acceptable forecast for use in the analysis of regional demand but may warrant adjustment to reflect a more balanced long-term trend.

With respect to the CAGR and linear regression forecasts, Altresco maintained that both time series regression formats are consistent with Siting Council precedent, provide good statistical results, and, barring major structural changes, would continue to demonstrate a strong relationship between time and growth in summer peak load. In addition, Altresco maintained that the rate of DSM implementation reflected in the regression forecasts is likely accurate in the short-run but too high in the long-run due to a likely decline in the rate of growth in DSM resources over time as cost-effective DSM opportunities decline. The Beach Association, on the other hand, argued that the CAGR regression forecast does not capture the continuing recession given that this recession is unlike previous recessions.

In a recent review, the Siting Board acknowledged that time series regression provides no means to capture possible shifts in peak load trends stemming from changes in underlying economic determinants and thus is an unsophisticated forecast methodology. See, EEC (Remand) at 250-251. The Siting Board, therefore, agrees with the Beach Association that the time series regression forecasts would not reflect significant differences in the current recovery from recoveries during the 1974 to 1991 time frame. However, based on this record, it is not clear that this recovery is significantly different from previous recoveries.

With respect to DSM, the Siting Board questions Altresco's assertion that its time series regressions, based on a 1974-1991 historical period can adequately capture current rates of DSM implementation. The Siting Board notes that, because formal utility programs did not appear until late in the historical period, a majority of peak load data points used in the Company's regression analysis could not reflect the annual amounts of DSM implementation observed in recent years. Thus, unless annual amounts of DSM implementation are significantly smaller over the forecast period than in recent years, the Company's time series regression forecasts can not fully capture DSM trends. See, EEC (Remand) at 250-252.

Overall, time series regression analyses are a long-recognized benchmark for establishing peak load trends, and have been considered in previous reviews of proposed generating facilities. As discussed herein, there is some likelihood that the Company's time series regression analyses of the 1974-1991 period resulted in under-representation of current DSM trends.

Based on the foregoing, the Siting Board finds that the linear regression forecast and the CAGR regression forecast provide acceptable forecasts for use in an analysis of regional demand, while recognizing that the forecast methodologies are not sophisticated and possible adjustments may be appropriate to reflect DSM trends over the forecast period.

With respect to the Company's multiple regression forecast, the Siting Board notes that the Company's forecast includes only one independent variable reflecting an economic, demographic or other determinant of load growth, and uses time as a second independent variable. As such, the multiple regression forecast is akin to a forecast based on the historical relationship of peak load to a single economic indicator -- an approach included in previous Siting Board reviews of regional need. While the Siting Board previously has addressed forecasts based on the relationship of peak load to gross national product ("GNP") or gross domestic product ("GDP"), Altresco based its multiple regression forecast on the relationship of peak load to another economic determinant, personal income.

In its previous reviews, the Siting Board or Siting Council has accepted forecasts based on GDP or GNP as alternative forecasts for evaluation of regional need, while, recognizing that such forecast methodologies were not sophisticated. See, EEC (Remand) at 213-214; Enron, 23 DOMSC at 44; EEC, 22 DOMSC at 236-237. In EEC (Remand), the

Siting Board also found that possible adjustments may be needed to reflect DSM trends over the forecast period. 90-100R at 213-214.

Here, although the Siting Board agrees with the Beach Association that economic activity cannot be predicted with certainty, the record does not support a conclusion that the Company's forecast of personal income is obviously biased, either upward or downward, such as to lead to a rejection of the forecast. However, the Siting Board is concerned that the forecast methodology, as applied by the Company, had no means to capture possible shifts in the relationship between personal income and peak load that would stem from changes in the rate of DSM implementation. Nevertheless, the Siting Board finds that the multiple regression forecast provides an acceptable forecast for use in an analysis of regional demand, while recognizing that the forecast methodology is not sophisticated and that possible adjustments may be appropriate to reflect DSM trends over the forecast period.[57]

c. DSM

(1) Description

Altresco indicated that, in order to incorporate DSM savings from utility-sponsored programs into the CELT forecast, NEPOOL first projects DSM savings over the forecast period by aggregating the DSM forecasts of the individual utilities (Exh. AL-13, at 17; Tr. 9, at 84).[58] However, Mr. La Capra asserted that NEPOOL projections of DSM savings likely overestimate the savings that the region will actually experience as a result of

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57 As noted above, during the course of the proceedings, the Company presented three additional demand forecasts -- two forecasts based on alternative fuel price scenarios and one demand forecast based on the DOE forecast of energy use (see n.33, above). The Siting Board considers these forecasts to represent sensitivity analyses of varying fuel price/energy use scenarios rather than forecasts of regional demand. Further, the Siting Board had no opportunity to question the Company about the development of these forecasts.

58 The Company stated that NEPOOL projects a CAGR in DSM of approximately 19 percent per year between 1991-1995, 8 percent per year between 1995-2000, and 4 percent per year between 2000-2007 (Exh. AL-13, at 17).

utility-sponsored programs (Exh. AL-12, at 10). In support, he stated that in previous CELT forecasts NEPOOL consistently has overestimated the contribution of DSM resources to peak demand reduction (Exh. AL-13, at 17). Specifically, he stated that since 1988, actual DSM savings, on average, have been approximately 18 percent less than the DSM forecast by NEPOOL (id. and attach. RLC-20).[59]

Mr. La Capra explained that NEPOOL's overforecast primarily is due to the manner in which individual utilities project savings from existing and planned DSM programs (id. at 19). He stated that utility projections are based on engineering estimates, and that such estimates generally overpredict actual savings as measured by impact evaluations (id.; Tr. 9, at 85).[60] Mr. La Capra stated that a review of the results of DSM evaluation studies has found that on average the actual savings from DSM were only 54 percent of forecasted savings, which were based on engineering estimates (id.; Exh. HO-RR-80).

The Company asserted that another reason for NEPOOL overprediction of DSM relates to recent changes in the regulatory climate (Exh. AL-13, at 20; Company Initial Brief at 44). Specifically, Altresco presented documentation detailing a number of utilities' requests for regulatory approval to lower their DSM budgets (Exh. HO-RR-79).

Altresco stated, therefore, that it would be inappropriate to evaluate regional need for new capacity based on the assumption that 100 percent of the utilities' projected DSM savings would be achieved, and instead, a more realistic DSM scenario should be considered

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59 The Company indicated that an analysis of NEPOOL DSM forecast accuracy indicates that: (1) actual DSM was less than the 1988 forecast of DSM by 3.7 percent for 1988, 8.6 percent for 1989, 6.3 percent for 1990 but was more than the 1988 DSM forecast of DSM by 1.8 percent for 1991; (2) actual DSM was less than the 1989 forecast of DSM by 50.4 percent for 1989, 49.4 percent for 1990, and 35.0 percent for 1991; (3) actual DSM was less than the 1990 forecast of DSM by 12.8 percent for 1990 and 12.0 percent for 1991; and (4) actual DSM was less than the 1991 forecast of DSM by 5.4 percent for 1991 (Exh. AL-13, attach. RLC-20).

60 Mr. La Capra stated that some reasons for overestimates include erroneous assumptions in engineering calculations, unanticipated interactions among DSM measures, technical problems, customer behavior changes and weather variations (Exh. AL-13, at 19).

(Exh. AL-13, at 20). Thus, the Company provided an alternative DSM forecast as a base DSM case which assumed that DSM growth above 1991 levels would be 25 percent less than the growth forecast by NEPOOL (id. at 20).[61] Mr. La Capra stated that the 25 percent was intended to be a median value, and that in fact 25 percent may be a modest assumption given the current overforecasting of DSM estimates (Tr. 9, at 84-86; Company Initial Brief at 46). He further stated that the 25 percent discount factor for the base DSM case was based on a number of considerations including (1) overall projections on the speed of implementation of conservation measures have been high, specifically overforecasted by almost 20 percent, and (2) the review of utilities actual savings over forecasted savings shows an average saving of only 54 percent (Tr. 9, at 85). Altresco also provided a high DSM case which assumed the NEPOOL DSM forecast (Exh. AL-13, at 23: Tr. 9, at 86).

(2) Analysis

The Company considered a discount of the 1992 CELT DSM by 25 percent of the increment over 1991 levels to be appropriate in the base case. The Siting Board notes that the average actual DSM underperformance for the years 1988 through 1991 is 18.2 percent, significantly lower than the 25 percent assumed by the Company. Further, the actual DSM underperformance relating to the 1989 forecast was significantly greater than DSM underperformance relating to the 1988, 1990 and 1991 forecasts, and the record indicates that if the 1989 forecast is omitted from the analysis, the average underperformance is only seven percent.

In reviewing a similar analysis of NEPOOL overforecasting of DSM in EEC (Remand), the Siting Board noted that the high level of overforecasting in the 1989 CELT forecast is not based on historical trends and may be an aberration, contributing to an unwarranted high underperformance average. Thus, the Siting Board concluded in that

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[61] The Company stated that under this scenario, DSM continues to grow at a robust rate with CAGRs of approximately 14.29 percent per year between 1991-1995, 6.15 percent per year between 1995-2000, and 3.03 percent a year between 2000-2007 (Exh. AL-13, at 17).

review that it would be reasonable to omit DSM underperformance from 1989 in considering the historical basis for any discounting of NEPOOL-projected DSM levels.

By omitting the actual DSM underperformance for 1989 and substituting instead the DSM underperformance for 1990, the next largest DSM underperformance, the average DSM underperformance is reduced to 8.4 percent. Accordingly, based on the foregoing, the Siting Board finds that it is appropriate to adjust the 1992 CELT DSM levels in the base case and that an adjustment of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels represents a reasonable base DSM case for the purposes of this review.[62]

As noted above, the Company included the NEPOOL base DSM forecast as a high DSM case. The Siting Board notes that the 1992 NEPOOL Resource Adequacy Assessment includes high and low DSM cases in addition to the base DSM case.[63] However, the 1992 NEPOOL Resource Adequacy Assessment was published after the Company prepared its regional need analysis. Therefore, for the purpose of this review, the Siting Board finds that the Company's high DSM case which is the 1992 NEPOOL base DSM case, represents a reasonable high DSM case.

d. Supply

(1) Description

Altresco presented three supply forecasts based on the 1992 CELT Report, a base supply case, high supply case and low supply case (Exhs. AL-13, at 21; AL-2, at 9-14).

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62 The Siting Board adjustment to the end-year CAGR forecast which incorporates the base DSM case, as adjusted, requires recalculation of the linear trend based on new values for DSM and resultant peak load in 2007 (see Section II.A.3.b.(1)(c), above). The new peak value for 2007 is 26,914 MW under the adjusted base DSM forecast. The projected growth is 450.9 MW per year.

63 The Siting Board notes that the high DSM values from the Resource Adequacy Assessment for the years 1996 through 2000 are: 1996 - 1,943 MW; 1997 - 2108 MW; 1998 - 2268 MW; 1999 - 2456 MW; 2000 - 2654 MW, and the low DSM values are: 1996 - 1485 MW; 1997 - 1612 MW; 1998 - 1725 MW; 1999 - 1824 MW; 2000 - 1922 MW (Exh. JH-1, at 65).

The Company explained that it considers the base case to be the most likely supply scenario, while the high case is a somewhat optimistic, although not unlikely, increase in supplies, and the low case is a somewhat pessimistic, although not unlikely, decrease in supplies (Exh. HO-N-20).[64]

In support of the supply cases, Altresco stated that the base supply case reflects the resources included in the 1992 CELT Report,[65] with two exceptions; (1) a minor correction to the Hydro-Quebec Vermont joint ownership purchases, and (2) a deduction from NEPOOL's estimate of capacity to reflect expected attrition and delays of committed future

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[64] As part of its initial analysis Altresco provided 16 contingency scenarios likely to affect either DSM or supply, as adjustments to the base, high and low supply cases (id. at 9-18 through 9-30). The Company stated that in selecting the contingencies, it focused on supply/DSM contingencies as Altresco felt it had adequately captured demand uncertainty through the base and alternative demand forecasts (Exh. HO-N-21). Altresco selected the 16 contingencies based on varying 11 parameters as follows: (1) high oil prices; (2) high and low DSM implementation; (3) restricted gas supply availability -- base, high and low; (4) major project delay; (5) high committed NUG project delay and attrition; (6) Clean Air Act implementation impacts; (7) older nuclear unit shutdown; (8) IRM process impacts; (9) regulatory delay of NUG projects and planned utility additions -- base, high and low; (10) 2 percent higher reserve requirement; and (11) existing committed utility unit attrition (Exh. AL-3, exhibit 9-L). The Company asserted that, although all of the contingencies except one increase expected need, there are many more potential events which could reduce the level of available supplies as opposed to increasing the level of such supplies (Exh. HO-N-22). However, as noted above, an updated contingency analysis was not included in the Company's updated regional analysis.

[65] The resources included in the 1992 CELT report include: (1) existing utility generation; (2) cumulative retirements; (3) cumulative life extensions; (4) committed non-utility generation; (5) net of planned, purchased and sales; (6) other committed capacity additions; and (7) net reratings and deactivations (Exh. AL-13, attach. RLC-23). The Company indicated that the category of committed non-utility generation includes those projects fully licensed, with all third party contracts and financing obtained, and those projects under construction (id.; Exh. HO-RR-61, at 55). The Siting Board notes that neither this proposed facility, the proposed Eastern Energy facility, nor the Enron facility are included in this category.

NUG capacity (Exh. AL-13, at 21-22).[66] The Company stated that the high supply case assumes the base case is increased by (1) the continuation of Hydro-Quebec Phase II beyond the year 2000, and (2) 50 percent of the planned, but not yet committed, utility generation project capacity pending regulatory approval, and 25 percent of the planned, but not yet committed, utility generation project capacity without regulatory approval (Exh. AL-2, at 9-16).[67] The Company stated that the low supply case assumes that the base case is decreased by the potential early cancellation of utility purchases from outside of NEPOOL, due to short-term excess capacity available within the pool (id. at 9-16).[68,69]

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66 The Company explained that, historically, a number of NUG facilities with signed contracts have failed to be completed or to come on-line as expected for a variety of reasons including failure to obtain financing, fuel supply or required permits (Exh. AL-2, at 9-15). The Company stated that the Massachusetts Electric Company ("MECo") prepared an analysis of NUG attrition and delay in a 1991 report entitled, "Alternative Energy Negotiation-Bidding Experiment" ("1991 MECo Report"), which includes a wide array of NUG projects at different stages of development (Exhs. AL-13, at 23; HO-N-16). The Company stated that in updating the 1991 MECo Report, it concluded that the average committed NUG failure rate is 32 percent, and that on average 50.5 percent of NUGs will experience a delay in their projected service date (Exh. AL-13, at 23).

67 The Company indicated that these two types of uncommitted utility capacity are categorized in the 1992 CELT Report as categories (L) -- regulatory approval pending, and (P) -- without regulatory approval, respectively (Exhs. AL-2, at 9-16; HO-RR-61, at 54). The record indicates that the principal projects in the L category include (1) the Taunton Energy Center, a proposed 150 MW facility, with an expected start date of January 1995 and (2) Edgar Energy Park, a proposed 306 MW facility, with an expected start date of January 1996 (Exh. HO-RR-61, at 31). The Siting Board notes that the Edgar Energy park has been indefinitely delayed by the developer, BECo. See, 1993 BECo Decision at 10. The P category includes 67 MW beginning in 1996, 5 MW beginning in 1997, 100 MW beginning in 1998, and a total of 722 MW beginning in 2000 and beyond (Exh. HO-RR-61, at 31).

68 The Company stated that it determined which supply contracts were likely to be cancelled based on a review of contracts held by purchasing utilities, discussions with purchasing utilities and first-hand knowledge of many of the power contracts held by major New England utilities (Exh. HO-N-19). Further, the Company stated that all of the identified contracts either will expire, although they are potentially renewable, or have an early cancellation provision (id.).

Altresco stated that it assumed a reserve margin of 22 percent of peak demand, consistent with the reserve margin generally used in the CELT Report, a forecast by the New England Governor's Council and recent NEPOOL experience (id. at 9-14). The Company indicated that the assumption of a 22 percent reserve margin is conservative as the NEPOOL reserve margin has varied between 17.0 percent and 50.2 percent over the 1970-1990 period (Exh. HO-N-13). However, the Company indicated that the 1990 NEPLAN Report called for a reserve margin of 20 to 22 percent between 1996 and the year 2005 to meet its reliability criterion (id.).[70]

(2) Analysis

As noted above, the Company presented a base supply forecast based on the 1992 CELT Report, a high supply forecast based on possible implementation of supply options listed in the 1992 CELT Report and a low supply forecast, based on possible losses of committed capacity included in the base case. The Company characterized the base supply forecast as the most likely supply scenario, while asserting that the high case is a somewhat optimistic, although not unlikely, increase in supplies, and the low case is a somewhat pessimistic, although not unlikely, decrease in supplies. The Siting Board notes that, for all supply forecasts, Altresco included NUG capacity only to the extent that such capacity is committed, and is existing or under construction. As noted in Section II.A.4.c., below, the Company excluded the committed capacity of the Enron facility from its original supply

[69](...continued)

[69] The Company calculated the potential NEPOOL purchase reductions, based on the 1992 CELT Report as follows: 1992 - 567 MW; 1993 - 484 MW; 1994 - 310 MW; 1995 - 260 MW; 1996 - 241; 1997 through 2007 - 191 MW per year (Exh. HO-RR-82).

[70] The Siting Board notes that within the 1992 Resource Adequacy Assessment Executive Report, NEPOOL targeted adjusted required reserve requirements to meet the reliability criterion for the high, reference and low demand forecasts (Exh. HO-JH-1, Table 3). These reserve margin requirements ranged from: (1) 21 percent to 22 percent for 1998; (2) 20 percent to 22 percent for 1999; and (3) 20 percent to 21 percent for 2000 (id.).

forecasts but later amended the Massachusetts supply forecast to include such capacity because the Enron facility was under construction.[71] We have assumed a comparable correction, i.e, an addition of 83 MW which represents the committed capacity of the Enron facility, to each of the Company's regional supply forecasts.

With respect to the base supply forecast, as noted above, the Company utilized the 1992 CELT Report capacity forecast with a minor correction to the Hydro-Quebec purchase and a deduction to reflect attrition and delay of future NUG capacity. The deduction was based on an analysis of the success rates and operational delays of NUG projects prepared by a utility.

The Siting Board agrees with the Company's general position that the base supply case should reflect capacity specified in the 1992 CELT Report. However, we have specific concerns with the methodology utilized by the Company in deducting capacity from the 1992 CELT report to reflect NUG attrition and delays. The utility analysis cited by the Company reflected a wide array of NUG projects at differing stages of development. However, the committed NUG projects included in the 1992 CELT capacity forecast are in an advanced stage of development, and thus would not necessarily have the same attrition or delay rate as those included in the utility analysis. For the purposes of deriving a base case, it would be preferable to base any adjustments to the 1992 CELT Report capacity forecast on specific circumstances.

Nevertheless, it is reasonable to assume that some of the committed NUG capacity included in the 1992 CELT Report would be cancelled or delayed. Accordingly, for the purposes of this review, the Siting Board finds that the base supply case, as adjusted by an additional 83 MW, represents a reasonable base supply forecast.

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71 The Siting Board notes that the Company also adjusted the Massachusetts need forecasts to reflect a decrease in Massachusetts purchases from the Power Authority of New York ("PASNY") based on updated data which indicated that original estimates were too high (Exh. JH-RR-2). However, no adjustment was made for purchases from PASNY in the regional analysis because there is no indication whether there was a change in overall purchases or in the allocation of purchases to Massachusetts.

With respect to the high supply forecast, the Siting Board also has concerns with Altresco's consideration of NUG capacity. In a recent review the Siting Board questioned the exclusion of uncommitted NUG capacity that is existing or under construction from the applicant's supply forecasts and found that such capacity should be included as part of a high supply case.[72] EEC (Remand) at 224-226. Thus, inclusion of 66 MW of uncommitted capacity of NUG projects that are existing or under construction would be appropriate for the high supply case.

In addition, the Siting Board notes that the Company assumed differing success rates for two categories of planned, uncommitted utility capacity in its high supply forecast. The Company assumed a 50 percent success rate for uncommitted utility capacity classified as "regulatory approval pending," and a 25 percent success rate for uncommitted utility capacity classified as "without regulatory approval." Given uncertainties in planning supply additions, it is reasonable for the Company to assume that not all planned, uncommitted utility capacity will be built and operational as of expected start dates. In fact, the 1992 CELT report includes on-line dates for two proposed utility projects that clearly are uncertain including (1) January, 1995 for the Taunton Energy Center, and (2) January, 1996 for the Edgar Energy Park. These two projects represent 95 percent of the total capacity included in this category. Thus, a 50 percent success rate for planned utility additions with regulatory approval pending is reasonable. The Company did not, however, provide a rationale for assuming a still lower success rate for the category of planned utility additions without regulatory approval. However, the Siting Board notes that the largest additions in this second category would

72 The consideration of the uncommitted capacity of these NUG projects is akin to the consideration of existing but uncommitted utility-owned capacity, such as the extension of the Hydro-Quebec contract, other contracts due to expire, or life extensions for existing generating units planned for retirement during the forecast period. Although the infrastructure is in place such that the above capacity reasonably could be available, the availability of capacity is not certain over the forecast period and, thus, is appropriate to exclude from the base case. The uncommitted capacity of NUG projects that are existing or under construction includes 3 MW for MASSPOWER and 63 MW for Enron.

occur starting in the year 2000 and, therefore, do not significantly affect the review of need for the proposed facility contained herein.

Therefore, for the purposes of this review, the Siting Board finds that the high supply case, as adjusted by an additional 83 MW, and further adjusted by an additional 66 MW of the uncommitted capacity of NUG projects that are existing or under construction, would represent a reasonable high level of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the high supply case, with the aforementioned adjustments, represents a reasonable high supply forecast for the purposes of this review.

Finally, with respect to the low supply case, the Siting Board notes that the Company's derivation of a low supply case differs in the regional and Massachusetts need analyses (see Section II.A.4.c., below). For the Massachusetts need analysis, Altresco derived its low supply forecast based on a reduction in supply of 632 MW for each forecast year to reflect the unavailability of the Pilgrim nuclear facility. For the regional need analysis, Altresco assumed a reduction in supply of 191 to 260 MW for the 1995 though 2007 time period based on potential early cancellation of utility purchases from outside of NEPOOL. However, as noted in the analysis of Massachusetts need, the Company did not discount its hypothesized loss of the specific nuclear unit to better reflect the limited probability of such a loss. Therefore, while the low supply forecast figures for regional need appear to be inconsistent with the Massachusetts low supply forecast, the deduction of 632 MW in the Massachusetts low supply case may have been excessive.

Accordingly, for the purposes of this review, the Siting Board finds that the low supply case, as adjusted by an additional 83 MW, would represent a reasonable low range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the low supply case, as adjusted, represents a reasonable low supply forecast for the purposes of this review.

Finally, with respect to the reserve margin, the Siting Board notes that the reserve margin assumed by the Company, 22 percent over the entire forecast period, is too high, given NEPOOL's expectations concerning long-term reserve margins. With respect to NEPOOL expectations, the 1992 Resource Adequacy Assessment Executive Report projects a downward trend in the reserve margin required to meet its reliability criterion. The midpoint of NEPOOL's target reserve margins to meet its reliability criterion for high, low and reference demand forecasts, after 1997, is: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000. The Siting Board also notes that, given the downward trend in NEPOOL-assumed reserve margin requirements, it also would be reasonable to assume a decline from the Company's assumed 22 percent reserve margin beginning in 1998. Therefore, based on the foregoing, for the purposes of this review, the Siting Board finds that the Company's reserve margin for the years 1998 through 2000 should be adjusted as follows: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000.

e. Need Forecasts

(1) Description[73]

The Company developed 33 need forecasts based on a comparison of its eleven demand forecasts -- the reference forecast, the high demand forecast, the high-low average forecast, and the end-year linear forecast each adjusted by base and high DSM scenarios; and the CAGR regression forecast, the linear regression forecast and the multiple regression forecast -- all adjusted by three supply forecasts -- base, high and low (Exh. AL-13). In comparing the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 170 MW of capacity in the early years of proposed project operation is: (1) 18 need forecast scenarios, 54.5 percent, in 1996; (2) 26 need forecast scenarios, 78.8 percent, in 1997; (3) 28 need forecast scenarios, 84.8 percent, in 1998; (4) 32 need forecast scenarios, 96.9 percent in 1999; and (5) 33 need forecast scenarios, 100 percent, in 2000 and beyond (id.). See Table 1. The Company indicated that comparison of the high-low average forecast incorporating Altresco's base DSM assumptions with the base supply forecast with updated information ("base need scenario") showed a need for over 170 MW in the early years of the proposed project,

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73 In comparing the need forecast scenarios in this section, the base, high and low supply forecasts were increased by 83 MW -- the committed portion of the Enron facility. See Section II.A.3.d., above.

specifically: (1) 371 MW in 1996; (2) 1,273 MW in 1997; (3) 2,061 MW in 1998; (4) 2,800 MW in 1999; and (5) 3,379 MW in 2000 (id.). See Table 1.

A summary of the 12 common-case need cases, those need cases common to both the regional and Massachusetts need analyses, indicated that the cumulative number and percentage of cases that demonstrated a regional need for at least 170 MW was: (1) 9 cases, 25 percent, in 1996; (2) 10 cases, 83.3 percent in 1997; and (3) 12 cases, 100 percent, in 1998 and beyond (Exh. HO-JH-RR-7).

(2) Arguments of the Parties

The Beach Association argued that the Company failed to demonstrate adequate need for the proposed facility (Beach Association Initial Brief at 2-7). The Beach Association stated that the most reasonable assessment of need is the reference forecast adjusted, by the 1992 CELT DSM, with the base supply case (id. at 5). However, the Beach Association stated that the aforementioned assessment of need does not demonstrate a need for the proposed facility by the year 1998 (id.).

(3) Analysis

As noted above, the Siting Board does not consider the high demand forecast in its analysis of regional need given that NEPOOL characterizes the forecast as having only a ten percent chance of occurring. See n.56, above. Therefore, the Siting Board focuses on the 27 need forecasts that reflect combinations of six demand forecasts, two DSM forecasts as adjusted, and three supply forecasts as adjusted.

In regard to the time period of our need review, the Siting Board notes that it is appropriate to consider need within a time frame beyond the first year of planned facility operation. EEC (Remand) at 232-233. The Siting Council previously considered capacity position beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of two NUG projects. See West Lynn, 22 DOMSC at 14, 33-34; Enron, 23 DOMSC at 49. The longer time frame is potentially useful regardless of whether need has been established for the first year of proposed operation. If need has been established for the first year, the longer time frame helps ensure that the need will continue over a number of years, and is not a temporary aberration. If need has not been established for the first year of proposed operation, a demonstration of need within a limited number of years thereafter may still be an important factor in reaching a decision as to whether a proposed project should go forward.[74] Thus, for the purposes of this review, the Siting Board finds that it is appropriate to explicitly consider need for the proposed facility within the 1996 to 2000 time period.

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) all supply forecasts by 83 MW to include the committed capacity of the Enron facility; (2) the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels in the base DSM case; (3) the Company's high supply forecast by 66 MW to include the uncommitted capacity of NUG projects that are existing or under construction; and (4) the Company's assumed reserve margin of 22 percent to reflect lower levels after 1997, specifically 21.5 percent for 1998, 21 percent for 1999, and 20 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has found that; (1) the reference forecast is an appropriate base case forecast for use in an analysis of regional demand for the years 1996 through 2007; (2) the high-low average forecast is an acceptable forecast for use in an analysis of regional demand but should not constitute a base case forecast; and (3) the end-year linear, linear regression, CAGR regression, and multiple regression forecasts provide alternative forecasts, with the caveats as noted above.

While accepting the high-low average, end-year linear, linear regression, CAGR regression, and multiple regression forecasts for use in an analysis of regional demand, the Siting Board identified concerns with these approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting

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[74] As explained above, an analysis of capacity position is not the only basis by which a facility proponent can establish need. Instead, need also can be established by a combination of factors related to the energy supply. See Section II.A.1.b., above.

Board addresses need based on two compilations of the Company's need forecasts as adjusted (1) a compilation including only those need forecasts incorporating the reference forecast, and (2) an overall compilation including all 27 need forecasts reflecting all three demand forecast methodologies.

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 170 MW in each year, from 1996 through 2000, is as follows:

Forecast	1996	1997	1998	1999	2000
Reference forecast (6 cases)	0 (0%)	0 (0%)	0 (10%)	4 (67%)	6 (100%)
Alternative forecasts (21 cases)	11 (52%)	20 (95%)	21 (100%)	21 (100%)	21 (100%)
Total (27 cases)	11 (41%)	20 (74%)	21 (78%)	25 (93%)	27 (100%)

The capacity positions under the need forecasts, as adjusted, are shown in Table 2. Considered with the base DSM forecast, and the base supply forecast: (1) the reference forecast shows a need for 334 MW in 1999; (2) the high-low average forecast shows a need for 879 MW in 1997; (3) the end-year linear forecast shows a need for 625 MW in 1997; (4) the linear regression forecast shows a need for 682 MW in 1996; (5) the CAGR regression forecast shows a need for 2005 MW in 1996; and (6) the multiple regression shows a need for 296 MW in 1997.

In sum, 11 of the Company's 27 need forecasts, including the 21 need forecasts that incorporate the high-low average, end-year linear, linear regression, CAGR regression, and multiple regression forecasts, show a need for at least 170 MW in 1996, 20 show a need for at least 170 MW in 1997, 21 show a need or at least 170 MW in 1998, 25 show a need for 170 MW in 1999, and 27 show a need for 170 MW in 2000. However, none of the six need forecasts that incorporate the reference forecast show a need for at least 170 MW in 1996 or

1997, or 1998, four such forecasts show a need for at least 170 MW in 1999 and six show a need for at least 170 MW in 2000.

Accordingly, giving added weight to the need forecasts based on the reference forecast for the reasons noted above, based on the foregoing, the Siting Board finds need for 170 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

f. Economic Efficiency

(1) Description

Altresco argued that, consistent with the standard of review established by the Siting Council in Enron, there is a need for the proposed project on economic efficiency grounds (Company Initial Brief at 52).[75] The Company indicated that economic efficiency savings available to the region from the proposed project include (1) the variable cost savings which result from Altresco's inclusion in the NEPOOL dispatch pool, and (2) the avoided cost of new capacity to meet identified regional need (Exh. HO-N-38).

In support, Altresco provided a series of detailed economic analyses with and without the proposed facility, based on NEPOOL dispatch practices (Exhs. HO-N-38S; HO-RR-58; HO-RR-60A). Altresco modelled NEPOOL's load duration curve and dispatch order over a twenty-year period, beginning in 1996 (Exhs. HO-N-38; HO-RR-60A; AL-12, at 16-17).[76]

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75 The Siting Board notes that the standard of review set forth in Enron predated City of New Bedford. In EEC (Remand), the Siting Board revisited its standard of review for establishing need in light of City of New Bedford. Specifically, the Siting Board found in that review that it is appropriate to consider economic efficiency benefits to the energy supply as a possible basis for a finding that there is a need for additional energy resources. Thus, the Siting Board reviews the Company's economic efficiency analysis consistent with the current standard of review and past Siting Council precedent.

76 Altresco provided an initial economic efficiency analysis, reflecting the 1990 CELT demand forecast, for a 20-year period beginning in 1995, but then updated and expanded its analysis based on the 20-year period beginning in 1996 (Exhs. HO-N-38; HO-N-58; HO-RR-60A).

Altresco stated that it projected a dispatch order for each year of the analysis by adjusting for scheduled plant retirements and additions, adding new generic capacity to meet projected regional capacity requirements,[77] escalating dispatch prices, and reranking generation facilities in order of their new dispatch prices (Exh. AL-12, at 19).[78,79]

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77 The Company modelled four types of new generic capacity: gas-fired combined cycle units; oil-fired combustion turbines; coal circulating fluidized bed ("CFB") units; and intermediate steam units (Exh. HO-N-33; Tr. 8, at 55-67). The Company indicated that most assumptions for these units, including fuel prices and variable operation and maintenance ("O&M") costs, were taken from the 1991 GTF (Exh. HO-N-34). Mr. La Capra noted that the analysis assumed CFB projects would not displace the proposed project in the dispatch queue, both because the proposed project's variable costs are fixed by its bid, and because CFB units may have fairly high variable O&M costs which would be included in the dispatch price (Tr. 8, at 60-62). He added that it was "unlikely" that the next generation of combined-cycle plants would have lower fuel prices than the Altresco project (id. at 63-66).

78 Altresco stated that it modelled NEPOOL's current dispatch order based on plant-specific information for each existing generating facility (Exh. AL-12, at 17). Specifically, Mr. La Capra obtained plant generating capacity, fuel types, quantity of fuel consumed, average heat rate, unit availability, must-run status, fuel cost, variable non-fuel costs, and dispatch price for each plant (Exh. AL-12, at 17). This information was obtained from FERC Form 1 filings, NEPOOL NX-12 forms, utility plant performance filings with the DPU, and NEPOOL's 1991 GTF (id.). Initial plant dispatch prices were based on actual NEPOOL dispatch price data for November, 1991 (id.). Dispatch prices for the proposed project were based on the project's bid prices in BECo's RFP 3 (Exh. HO-N-36; Tr. 8, at 29). The Company calculated the "expected annual capacity" for each plant by multiplying its seasonally-weighted average annual capacity by its target equivalent availability factor (id. at 18). Mr. La Capra stated that availability factors, as well as ratings and dispatch prices, were adjusted when necessary to account for seasonal variations (Tr. 8, at 41-44).

79 The Company indicated that it assumed that NEPOOL would dispatch on a purely economic basis, with exceptions made for units which must operate for technical or contractual reasons (Exh. AL-12, at 17-18). Mr. La Capra stated that a total of 9196 MW were classified as "must-run" capacity, including all of NEPOOL's nuclear units, conventional hydropower, baseload external purchases, purchases from existing and committed non-utility generation, and portions of certain existing fossil units (Exh. AL-12, p. 18). He noted that this may overstate future must-run capacity, since: (1) some existing and committed NUGs may be dispatchable, rather than must-run; (2)

(continued...)

Altresco used two alternative costing methods to estimate the avoided cost of new capacity: (1) estimation of avoided capital costs and annually declining carrying charges for utility-owned combustion turbines ("declining carrying charge method");[80] and (2) estimation of avoided capacity payments based on NEPOOL deficiency charges ("NEPOOL deficiency charge method") (Exh. HO-N-38). For each avoided cost method, the Company analyzed a range of scenarios varying assumptions as to (1) future load growth, (2) future fuel prices, and (3) the mix of future generating units (Exhs. HO-RR-58, HO-RR-60A).[81] Specifically, Altresco analyzed the economic savings attributable to the proposed project for three load growth scenarios, including the reference forecast, the Company's high-low average forecast, and the 1990 CELT Report forecast (Exh. HO-RR-60A).[82] The Company considered each of these forecasts in conjunction with two fuel price forecasts, the Summer, 1991 DRI forecast, and the May, 1991 forecast by the WEFA Group (formerly Wharton Econometrics) (id.).[83] Finally, in conjunction with the 1990 CELT report load forecast, the

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[79](...continued)
some units which are currently classified as must-run in order to maintain voltage support may not be required if new projects come online in the area; and, (3) some older must-run units may be retired before the end of the 20-year analysis period (Exh. HO-N-35). Mr. La Capra noted that overstatement of NEPOOL's must-run capacity leads to an understatement of the economic efficiency savings available from the project (id.).

[80] The Company estimated the avoided capacity cost under the declining carrying cost method based on a utility-owned gas turbine unit depreciated over 20 years.

[81] The Company used its 1992 base case supply scenario in these analyses (see Section II.A.3.d., above) (Exh. HO-RR-60A).

[82] Mr. La Capra claimed that using the 1992 CELT Reference case as a low demand case and the 1990 CELT case as a high demand case creates a reasonable range in which future demand might fall (Tr. 8, p. 89).

[83] Mr. La Capra indicated that the 1991 DRI forecast predicted flat fuel prices for the first two years, followed by several years of sharp increases and an extended period of slower real growth (Tr. 8, at 81-82). Mr. La Capra stated that he believed this forecast was probably high, especially in early years, and offered the WEFA Group
(continued...)

Company provided alternative analyses assuming that the mix of new resources in early years would be heavily weighted toward base load capacity, rather than equally weighted between base load capacity and peaking capacity (Exh. HO-RR-58).[84]

Thus, for each of the two methods used to reflect avoided capcity cost, the Company presented estimates of the 20-year net present value ("NPV"), in 1996 dollars, of the economic efficiency savings available from the proposed project under eight scenarios.[85] The Company's analysis indicates that the proposed project would provide 20-year NPV savings ranging from a low of $48.5 million to a high of $224.0 million (Exhs. HO-RR-58; HO-RR-60A; Company Initial Brief at 60). Table 3 presents a summary of the economic efficiency effects of the proposed project based on the Company's overall analysis for the 1996-2015 period. Table 4 shows the energy cost and capacity cost effects of the proposed project for the years 1996 through 1999, based on the Company's analyses that incorporate the 1992 CELT reference forecast.

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[83](...continued)
forecast as a "lowest reasonable boundary" (id. at 90). Mr. La Capra noted that higher fuel prices for the units dispatched after the proposed project result in greater economic efficiency savings attributable to the proposed project (id. at 87).

[84] The Company's original analysis assumed that new generic resources would be split evenly between gas-fired combined-cycle plants (baseload) and oil-fired turbines (peaking) until 1998, after which intermediate oil-fired steam plants and CFB technologies would enter the mix (Exh. HO-N-38, Attachment C; Tr. 8, at 57-58). Mr. La Capra stated that NEPOOL's current mix of 80 percent baseload capacity and 20 percent peaking capacity does not represent the historical mix, and that utilities are likely to correct the imbalance by acquiring additional peaking capacity (Tr. 8, at 69-70). In response to a Siting Board request, Mr. La Capra developed an alternative growth path which assumed that this correction would be delayed until 1998, until which time new capacity would be 80 percent baseload, 20 percent peaking (Exh. HO-RR-58; Tr. 8, at 73-77).

[85] For the respective scenarios, the avoided capacity cost estimates developed under the declining carrying charge method were higher in the early years of the proposed project, but lower over the overall 20-year period, compared to the avoided capacity cost estimates that the Company developed based on the NEPOOL deficiency charge method (Exhs. HO-RR-58, HO-RR-60A).

Mr. La Capra asserted that the economic efficiency savings available from the proposed project would increase under a variety of policies aimed at reducing regional emissions (Tr. 8, at 48-51).[86] Mr. La Capra also claimed that the economic efficiency savings would continue, although at a lower level, in the case of the early retirement of existing generating plants (id. at 51-54). Finally, he indicated that the proposed project's place in the dispatch queue, and hence its economic efficiency savings were related to its fuel transportation package (id. at. 94-95).

(2) Analysis

In the past, the Siting Council determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985), and Boston Gas Company, 11 DOMSC 159, 166-168 (1984), 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 with retail service territories outside of Massachusetts, the Siting Council standard indicated that need may be established on either reliability or economic efficiency grounds. Enron, 23 DOMSC at 55-56; EEC, 22 DOMSC at 207-241; NEA, 16 DOMSC at 344-360.

86 Specifically, Mr. La Capra stated that, if high-emission plants added emission control devices, these would be treated by NEPOOL either as a fixed cost, in which case the dispatch order would not be changed, or as a variable operating cost, in which case the proposed project would provide greater savings because of the increased cost of the generation it displaced (Tr. 8, at 48-50). Mr. La Capra also indicated that if NEPOOL changed its practices to dispatch based on variable cost plus an environmental adder, gas-fired plants such as the proposed project would rise in the dispatch order (id. at 50-51). Finally, Mr. La Capra stated that, if an emissions allowance trading program were implemented, gas-fired plants would rise in the dispatch order (Tr. 8, at 48).

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. Enron, 23 DOMSC at 49-55; EEC, 22 DOMSC at 210-211; West Lynn, 22 DOMSC at 14; MASSPOWER, 20 DOMSC at 19.

In MASSPOWER, West Lynn and EEC, the Siting Council rejected Companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Council noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds.

In Enron, for the first time, the Siting Council found that a non-utility generating project was needed for economic efficiency purposes (23 DOMSC at 55-62). The Siting Council noted that such a finding, based on comprehensive analyses of NEPOOL dispatch both with and without a proposed project, is necessarily project-specific. Id. at 58. The Siting Council indicated that since, unlike economic efficiency gains associated with specific PPAs, regional economic efficiency gains are not contractually guaranteed, the degree to which they are assured would be a critical factor in our evaluation of regional need for economic efficiency purposes. Id. at 58-59. The Siting Council also identified the magnitude and timing of such gains as critical to our review. Id. at 59.

Here, the Company has provided a detailed description of the methodology and assumptions used in its analysis of economic efficiency savings. The Company's methodology is based on reasonable assumptions, and is very similar to that accepted by the Siting Council in Enron.

Further, Altresco's use of multiple scenarios allows the Siting Council to evaluate the degree to which economic efficiency savings are assured in face of uncertainty about future conditions. Specifically, the Company's sensitivity analyses indicate that, over its life, the proposed project will generate significant and quantifiable savings to the region under a range of assumptions regarding potential load growth, fuel prices, avoided capacity costs, and types of generation built in the region in the future.

The Siting Board notes that the lowest of the three load growth forecasts used by the Company in its sensitivity analysis, the reference forecast, was accepted in Section II.A.3.b(3), above, as an appropriate base case demand forecast in evaluating need for reliability purposes. Of the two remaining forecasts, the 1990 CELT forecast was not included in the analysis of reliability need and the high-low average forecast was included as a possible forecast but not as a base case forecast in that analysis. However, the high-low forecast and the 1990 CELT forecast serve to demonstrate the sensitivity of the Company's economic efficiency analysis results to high-side variability in the demand forecast.

The analyses provided by the Company indicate that, even under the base case demand forecast, the proposed project would provide substantial economic efficiency savings over 20 years. However, the timing of these savings is extremely sensitive both to the demand forecast and to the costing approach for avoided capacity. Under the cases incorporating the reference forecast, continuous annual savings would not begin to be realized until 1999 or 2000, and cumulative savings would not be realized until 2003. Under the cases that incorporate one of the two higher demand forecasts, continuous and cumulative economic efficiency savings would be realized beginning in most instances by 1996, assuming use of the declining carrying charge method to cost avoided capacity, and by 1999, assuming use of the NEPOOL deficiency charge method. See Table 3.

The Siting Board notes that the actual economic efficiency gains that would be achieved under the 1992 CELT reference forecast cases may be less than that indicated in Table 3, since the Company's analysis reflects avoided capacity costs beginning in 1996, although the capacity is not needed for reliability purposes until 2000 under that demand forecast. As shown in Table 4, the Company's analysis assumed cumulative 1996-1999 NPV avoided capacity costs of $86.1 million under the declining carrying charge method and $74.5 million under the NEPOOL deficiency charge method. Table 4 further shows that, if only the displaced energy cost is considered, the proposed project would provide a cumulative NPV 1996-1999 cost displacement ranging from $181.6 million to 183.8 million, or 65.8 percent to 66.6 percent of the cumulative NPV 1966-1999 total fixed and energy cost of the proposed project.[86A]

Thus, while the proposed project likely would provide economic efficiency savings over 20 years, the Company's analysis failed to show that continuous annual savings would be attained prior to 2000 -- the first year of regional need for reliability purposes. Further, if the NPV amounts for avoided capacity costs are removed from the Company's analysis for the years 1996 through 1999, the remaining NPV amounts for displaced energy costs are well below 100 percent of the NPV fixed and energy costs for such years. Therefore, the Company has not demonstrated a need for the proposed project in years prior to 2000, based on economic efficiency.

The Siting Board finds that Altresco has established that New England would realize economic savings of a substantial magnitude from the operation of the proposed project over the likely term of its PPAs, and that, under future demand levels consistent with the reference forecast, economic efficiency savings would begin to accrue on a continuous basis in 2000 or later.

Accordingly, the Siting Board finds that Altresco has established that, beginning in 2000 or later, New England will need 170 MW of the additional energy resource from the proposed project for economic efficiency purposes.[87]

86A We note that the exclusion of 1996-1999 avoided capacity costs removes or significantly reduces the 1996-2015 NPV savings shown in Table 3 under the 1992 CELTS reference forcast cases. However, we recognize that with a delay in the project on-line date, the Company likely could show 20-year NPV savings more closely reflecting those shown in Table 3.

87 The Siting Board notes that this finding, in and of itself, would not be sufficient to establish need for a project, such as the Altresco project, with an expected on-line date of 1996. However, this finding supports our finding of regional need for the project for reliability purposes.

4. Massachusetts' Need for Additional Energy Resources

a. Introduction

Altresco asserted that there is a need for new capacity in Massachusetts beginning in 1997 or earlier, and continuing beyond 1997 (Company Second Supplemental Brief at 29; Exh. AL-42 at 1). The Company further asserted that the need for new capacity in Massachusetts arises earlier than the need for new capacity in New England as a whole (id. at 30). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based in part on 1992 forecast documents and other data published by NEPOOL and, as necessary, prorated to Massachusetts by the Company (Exhs. AL-42; HO-MN-5; HO-MN-9; HO-MN-10; HO-MN-11; HO-MN-12). The Company combined its demand and supply forecasts to provide a series of Massachusetts need forecasts, and also subjected the need forecasts to a variety of contingency tests to evaluate the sensitivity of the need forecasts to the uncertainty inherent in underlying demand and supply forecast assumptions (Exhs. AL-42; HO-MN-14; HO-MN-15; HO-MN-16; HO-MN-17). In addition, the Company presented analyses of transmission system reliability benefits and environmental benefits associated with displacement of more polluting generation by operation of the proposed project.

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the other factors, i.e. transmission system benefits and air quality benefits, analyzed by the Company in support of Massachusetts need for the project.

b. Demand Forecasts

(1) Description

The Company presented 11 forecasts of Massachusetts adjusted peak load demand (Exh. AL-42, attach. RLC-9). The Company stated that it based its Massachusetts demand forecasts on five different demand forecast methodologies and three different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 4). To derive its 11 demand forecasts, the Company indicated that it adjusted results from three of its forecast methodologies to reflect the three respective DSM forecasts (id.). The Company utilized results from the remaining two forecast methodologies without separate reductions to reflect DSM (id.).

(a) Demand Forecast Methodologies

The five demand forecast methodologies utilized by the Company included: (1) the NEPOOL 1992-2007 energy and peak load forecast for Massachusetts, a companion forecast to the reference forecast incorporated in the Company's regional need analysis ("Massachusetts reference forecast"); (2) a Massachusetts expected value forecast, derived from the NEPOOL 1993-1997 expected value load forecast presented in the 1992 Resource Assessment ("Massachusetts expected value forecast"); (3) a variation of the Massachusetts reference forecast, based on a CAGR projection between 1992, or first-year, peak load and 2007, or end-year, peak load as forecasted by NEPOOL in the Massachusetts reference forecast ("Massachusetts end-year CAGR forecast"); (4) a historical time series linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("Massachusetts linear regression forecast"); and (5) a historical time series CAGR regression forecast, based on a projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("Massachusetts CAGR regression forecast") (id. at 4). The Company stated that its Massachusetts reference forecast was obtained directly from a published NEPOOL source, and the remaining demand forecasts were based on data derived largely from reports published by NEPOOL and NEPLAN (Exhs. AL-42, at 5 and attach. RLC-4; Company Second Supplemental Brief at 14).

Massachusetts CAGR regression forecast -- correspond to demand forecast methodologies used in the regional need analysis (Exh. JH-RR-7).[88] The Company characterized the Massachusetts reference forecast as a reasonable long term forecast, but cautioned that the forecast was overly pessimistic in the short term (Exhs. HO-MN-2; HO-MN-3).[89]

The Company stated that it presented one of its remaining demand forecasts -- the Massachusetts expected value forecast -- as an attractive base case forecast (Exh. HO-MN-2). The Company noted that the expected value forecast is comparable to its base case forecast in the regional analysis -- the median of the high and low forecasts in the 1992 CELT Report (Tr. JH-1, at 17).

To derive the Massachusetts expected value forecast, the Company stated that it prorated, on a year-to-year basis, the forecasted demand in the NEPOOL expected value forecast by the ratio of the forecasted demand in the Massachusetts reference forecast to the forecasted demand in the NEPOOL regional reference forecast (Exhs. AL-42, at 5; JH-RR-1). The Company stated that, since the reference forecast and the Massachusetts reference forecast are consistent in terms of methodology and assumptions, it is reasonable to use them for purposes of prorating the expected value forecast (Exh. HO-MN-2).

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88 The Company stated that the base case that it used in the regional analysis -- the median of the high and low forecasts in the 1992 CELT Report -- was not used in the Massachusetts need analysis, as NEPOOL did not develop a high and low demand forecast for Massachusetts (see Section II.A.3.b.(1), above) (Exh. HO-MN-2). Further, Altresco indicated that the 1992 Resource Assessment was not available at the time the regional need analysis was conducted, thereby precluding the use of an expected value forecast (id.). However, Mr. La Capra asserted that had NEPOOL developed a high and low demand forecast for Massachusetts, he would have submitted the average of the two (as in the regional analysis) as another Massachusetts need case, as well as presenting the expected value derived from the Resource Assessment for regional need if it were available (Tr. JH-1, at 16).

89 The Company indicated that its Massachusetts reference forecast reflects an average annual growth rate in adjusted peak load of 2.21 to 2.55 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. AL-42, attach. RLC-9).

The expected value is the weighted average of all possible outcomes of a probability distribution (Exh. HO-JH-2, at 22; Tr. JH-1, at 47). The Company explained that the expected value is the mean value of the probability distribution (Tr. JH-1, at 47-48). The Company explained that the 1992 Resource Assessment provided the expected value of the load forecast for the years 1993 through 1997 (Exhs. HO-JH-RR-1; HO-JH-2). Altresco then extrapolated values for the years 1998 and beyond based on a linear regression of the NEPOOL forecast data for the 1993 through 1997 period (Exh. JH-RR-1).

In support of its selection of the Massachusetts expected value forecast as a base case forecast,[90] Altresco identified the following attributes of the underlying NEPOOL expected value forecast: (1) it is the product of a sophisticated methodology; (2) it incorporates a probabilistic approach which is preferable to a deterministic approach because it is inherently better able to reflect the potential impacts of the significant uncertainties that affect the timing and magnitude of the need for new energy resources; (3) NEPOOL appears to assign a higher degree of credibility to the resource assessment than the CELT forecast; and (4) it is a conservative basis for planning for new supplies (Exh. HO-MN-2).[91]

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90 The Company stated that, over the last three years of the forecast period, the Massachusetts expected value forecast/low DSM is the highest forecast, and thus also provides a reasonable high case forecast methodology for that time frame (Exh. HO-MN-7). The Company indicated that the Massachusetts expected value forecast, although only the third highest forecast during the early years of the forecast period, incorporates higher peak load growth that allows it to surpass all forecasts by the end of the forecast period (Exh. AL-42, attach. RLC-9). Specifically, the Massachusetts expected value forecast surpasses the Massachusetts linear regression forecast beginning in 1997 to 1999, depending on which of the Company's three DSM forecasts is assumed (id.). Therefore, Mr. La Capra concluded that the expected value forecast with low DSM is overall the best selection for a high case estimate (Tr. JH-1, at 68).

91 The Company indicated that its Massachusetts expected value forecast reflects an average annual growth rate in adjusted peak load of 2.50 to 2.83 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. AL-42 attach. RLC-9).

In addition to presenting the Massachusetts reference forecast based directly on NEPOOL's deterministic forecast for Massachusetts, the Company presented the Massachusetts end-year CAGR forecast as a useful alternative to the Massachusetts reference forecast (Exh. AL-42, at 5). The Company indicated that its end-year CAGR forecast methodology assumes that Massachusetts adjusted peak load in 2007 will be the same as forecasted by the Massachusetts reference forecast, but utilizes the average annual 1992-2007 compound growth rate underlying that 2007 peak load level to forecast demand for the intervening years (Exhs. HO-MN-39, attach. 7-5; HO-MN-45).[92] The Company stated that, by assuming a constant growth rate consistent with the long term outcome of the Massachusetts reference forecast, the end-year CAGR methodology dampens the short-term pessimism of the Massachusetts reference forecast, and is likely to be more accurate than the reference forecast over the short and medium terms (Exh. HO-MN-3).[93] The Company added that the use of a constant annual growth forecast for supply planning purposes would

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92 The Company indicated that, to apply the end-year CAGR methodology to adjusted peak load, it first derived Massachusetts adjusted peak load values for 1992 and 2007 by adjusting NEPOOL's Massachusetts peak load forecast to reflect Altresco's DSM assumptions for those years, and then derived a CAGR trend forecast of Massachusetts adjusted peak load for the intervening years (Exh. AL-42, attach. RLC-9). The Company indicated that its Massachusetts end-year CAGR forecast reflects a constant annual growth rate of 2.21 to 2.55 percent, depending on which of Altresco's three DSM forecasts is used (id.).

93 As an example of the relatively flat, short-term trend, the Company indicated that its Massachusetts reference forecast projects 1992-1995 increases in adjusted peak load of 1.42 to 1.99 percent, depending on which of Altresco's three DSM forecasts is used (Exh. AL-42, attach. RLC-9). In terms of annual MW increments, the Company's Massachusetts reference forecast shows average annual increases in adjusted peak load of 128 MW to 181 MW between 1992 and 1995, depending on which DSM forecast is used, and 148 MW to 200 MW between 1992 and 1997 -- the on-line date of the proposed project (id.). However, indicative of the higher rate of increase in the longer term, the Company's Massachusetts reference forecast shows average annual incremental increases in adjusted peak load of from 271 MW to 308 MW between 1997 and 2007 (id.).

decrease the possibility that prolonged periods of oversupply or undersupply of generating capacity would occur (id.).

The Company stated that it developed its Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast based on performing time series regression analyses of 1974-1991 weather-normalized Massachusetts summer peak load data derived from NEPOOL data (Exh. AL-42, at 6, attach. RLC-5, RLC-6).[94] The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the regression equations, and claimed that a moderate to high amount of DSM thus was incorporated in the regression forecasts (Exh. HO-MN-4). The Company indicated that the projected growth in Massachusetts peak load would be 179 MW per year under the linear regression forecast[95] and 2.39 percent per year under the CAGR regression forecast (Exh. AL-42, attach. RLC-5, RLC-9). The Company stated that both regression formats show good statistical results for the 1974-1991 historical data (id.; Exh. AL-42, at 6).

The Company asserted that the Massachusetts linear regression forecast represents a reasonable low case, claiming that the Siting Council's decision in West Lynn supports the view that a linear regression forecast constitutes an "approximate minimum" for a long-term forecast (Exh. HO-MN-8; Company Second Supplemental Brief at 6-7).[96] The Company

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94 The Company stated that weather-normalized data was not available by state, and that it approximated such data by multiplying NEPOOL's 1974-1991 weather-normalized summer peak load data by the year-to-year ratio of actual Massachusetts summer peak load to actual NEPOOL summer peak load (Exh. HO-MN-5).

95 Over the 1992-2007 forecast period, the linear trend corresponds to a CAGR of 1.71 percent (Exh. AL-42, attach. RLC-9).

96 Based on the Company's projections of adjusted peak load, the Massachusetts linear regression forecast actually is second highest at the beginning of the forecast period, surpassed only by the Massachusetts CAGR regression forecast (Exh. AL-42, attach. RLC-9). However, depending on which of the Company's three DSM forecasts is assumed, the Massachusetts linear regression forecast is surpassed by the Massachusetts expected value forecast beginning between 1997 and 1999, by the Massachusetts end-year CAGR forecast beginning between 1999 and 2003, and by the Massachusetts reference forecast beginning between 2002 and 2005 (id.). In (continued...)

also asserted that the Massachusetts CAGR regression forecast, the highest forecast over all but the last three years of the forecast period, represents a reasonable high case over that 1992-2004 period (Exh. HO-MN-7).

(b) DSM Forecasts

The Company stated that it utilized NEPOOL's DSM forecast for Massachusetts, which corresponds to NEPOOL's DSM forecast for New England contained in the 1992 CELT Report, to develop a range of DSM forecasts for the Massachusetts need analysis (Exh. AL-42, at 6-7). Repeating arguments from its regional need analysis (see Section II.A.3.c., above), the Company stated that NEPOOL historically has overforecast DSM, and that, therefore, the Company considers NEPOOL's Massachusetts DSM forecast to be a high case DSM forecast for purposes of the Massachusetts need analysis (id.). Consistent with the regional need analysis, the Company stated that a DSM forecast for Massachusetts which assumes 75 percent of the planned increase in DSM above 1991 levels, as forecast by NEPOOL, would represent a reasonable base case DSM forecast (id.). Mr. La Capra stated that the selection of a 25 percent decrease in DSM is intended to be a reasonable average, since DSM has fallen both at a higher and lower level, but more often at a higher level (Tr. JH-2, at 14). Similarly, the Company stated that it developed a Massachusetts DSM forecast which assumes 50 percent of NEPOOL's planned increase in DSM for Massachusetts above 1991 levels as a low case DSM forecast (Exh. AL-42, at 6-7).

(2) Positions of Intervenors and Company's Response

The Beach Association argued that all of the demand cases, with the exception of the reference forecast, have multiple methodological deficiencies (Beach Association

[96](...continued)
defending its selection of the linear regression forecast as a reasonable low case, the Company stated that forecasts based on the Massachusetts reference forecast rely on overly pessimistic economic assumptions in the short term (Exh. HO-MN-8). However, the Company stated that the reference forecast with base DSM is a reasonable low demand forecast subject to the prior caveats (id.).

Supplemental Reply Brief at 30). The Beach Association stated that the following flaws are associated with the expected value forecast: (1) the expected value forecast does not have an equal probability of being too high or too low, as stated by Mr. La Capra (citing, Tr. JH-1, at 47); (2) the confidence level is over 50 percent,[97] and may be as high as 64 percent in the years 1998 and 1999;[98] (3) the expected value forecast should not be extended past the year 1997, as cautioned in the 1992 Resource Assessment[99]; and (4) the expected value forecast is based on unsupported ratios of Massachusetts demand versus New England demand[100] (id. at 10, 13, 19, 41).

The Beach Association argued that proponents in previous Siting Council cases have not utilized base case forecasts based on an expected value forecast (Beach Association Supplemental Reply Brief at 6). The Beach Association further stated that an expected value forecast is a probabilistic forecast rather than a deterministic forecast, and assigns a greater weighted value to a forecast outcome if it shows a larger margin of deficiency relative to the

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97 The Beach Association asserted that the confidence levels for the years 1995, 1996, and 1997 would be 52 percent, 53 percent and 57 percent respectively (Beach Association Supplemental Brief at 14).

98 The Beach Association asserted that in EEC the Siting Board stated:

> "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"

(Beach Association Supplemental Reply Brief at 17, citing, EEC, 22 DOMSC at 240).

99 The Beach Association cited the Executive Report of the Resource Assessment (see Exh. HO-JH-1, at 17) as stating "The uncertainty surrounding future load levels and resource availability make it difficult to perform a meaningful probabilistic analysis over the long term" (Beach Association Supplemental Brief at 19).

100 The Beach Association asserted that deriving the base demand forecast -- the Massachusetts expected value forecast -- from the New England expected value forecast destroyed the sophistication of the NEPOOL expected value forecast for New England (Beach Association Supplemental Brief at 17).

50 percent confidence level (id. at 18). The Beach Association argued that the expected value forecast is not conservative, as purported by the Company (id. at 22). Finally, the Beach Association argued that the Company's base demand forecast, combining the Massachusetts expected value forecast with the base DSM forecast, has essentially the same results as the high demand forecast, combining the Massachusetts expected value forecast with the low DSM forecast, for the 1996-1999 period -- the years in which need must be established for the proposed project (Beach Association Supplemental Brief at 17, 18).

The Beach Association also argued that the Massachusetts end-year CAGR forecast allows for a higher chance of oversupply, has no use in planning purposes, and is calculated to be higher in the years that the proponent wants it to be higher (Beach Association Supplemental Reply Brief at 24, 25).

In regard to the Massachusetts linear regression and the Massachusetts CAGR regression forecasts, the Beach Association argued that the growth increments have been set at artificially high levels, as the slope of the regression is too high to be used as a valid methodology (id. at 17). Further, the Beach Association pointed out that the regression line did not run through last years value (id. at 26). While admitting that forecast methodologies are not required to be sophisticated, the Beach Association argued that lack of sophistication does not excuse an erroneous methodology (id.). In addition, the Beach Association argued that the Massachusetts CAGR regression forecast is unreliable in a recessionary period, as the previous growth rate will not be achieved (id. at 27, 28).

Finally, based on the above methodological flaws, the Beach Association argued that the Massachusetts reference forecast appears to be reasonable and represents a better base case than the Massachusetts expected value forecast, or any of the other forecasts (id. at 23). The Beach Association argued that even a 50 percent confidence level could lead to unnecessary capacity additions and that the Siting Board should summarily reject any proposed capacity additions based on higher confidence levels (Beach Association Supplemental Brief at 30).

With respect to DSM, the Beach Association argued that a better base DSM case would be 90% of planned growth versus the 75 percent utilized by the Company (id. at 39).

The Company responded that the Siting Board has not adopted a standard that planning should be done to only the 50 percent confidence level (Company Supplemental Reply Brief at 3). Further, the Company stated that even if the Siting Board determined that a 50 percent confidence level is appropriate, NEPOOL's reference forecast reflecting a 50 percent confidence level is dependent on the reasonableness of the underlying methodology and assumptions, which the Company has maintained are biased downward (id. at 4). Further, Altresco responded that the Massachusetts expected value forecast is the best value to use given the probabilistic nature of the supply planning process (id.). Finally, the Company responded that the Massachusetts linear regression forecast was prepared consistent with Siting Council precedent (id.).

(3) Analysis

As described above, the Company utilized five demand forecast methodologies for its Massachusetts need analysis, of which three -- the Massachusetts reference forecast, the Massachusetts linear regression forecast, and the Massachusetts CAGR regression forecast -- correspond to methodologies used in the regional need analysis. The Company and the Beach Association generally adopted positions regarding the Massachusetts reference forecast, the Massachusetts linear regression forecast, and the Massachusetts CAGR regression forecast matching those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3.b.(3), above. The Siting Board notes that the Company's base case, the Massachusetts expected value forecast was not presented in the regional analysis (see n.88).

Consistent with its findings regarding the Company's regional need analysis concerning the 1992 reference forecast, the Siting Board finds that the Massachusetts reference forecast is an appropriate base case forecast for use in an analysis of Massachusetts demand for the years 1996 to 2007.

With regard to the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast, the Company maintains that both time series regression formats provided good statistical results and are consistent with Siting Council precedent, while the

Beach Association criticized the time series forecasts as an unsophisticated, erroneous approach. Further, the Beach Association argued that the CAGR regression is not a reliable methodology to be utilized in a recessionary period.

Consistent with the regional need analysis, the Siting Board agrees with the Beach Association's position that time series regression provides no means to capture possible shifts in peak load trends stemming from changes in underlying economic determinants, and thus is an unsophisticated forecast methodology. However, we disagree with the Beach Association's argument that outright rejection of Altresco's time series regression forecasts is warranted. Rather, any evidence of theoretical factors detracting from the applicability of a time series regression or other trending forecast affects the weight the Siting Board places on such forecasts in its determination of need.[101]

Therefore, consistent with its findings regarding the Company's regional need analysis, the Siting Board finds that the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast provide acceptable forecasts for use in an analysis of Massachusetts demand, while recognizing that the forecast methodologies are not sophisticated and that possible adjustments may be needed to reflect DSM trends over the forecast period.

The other two Massachusetts demand forecast methodologies -- the Massachusetts expected value forecast and the Massachusetts end-year CAGR forecast -- do not represent counterparts to forecast methodologies included in the Company's regional need analysis. Thus, we address below the positions of the parties regarding these Massachusetts demand forecast methodologies.

With respect to the Massachusetts expected value forecast, Altresco considered this forecast to be a base case forecast while the Beach Association expressed numerous methodological concerns with the forecast.

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101 With respect to the Company's position that Siting Board precedent supports a conclusion that the Company's linear regression forecast is an "approximate minimum" forecast, the Siting Board considered and rejected a similar argument in EEC (Remand) at 239-240, 251.

In its last facility review the Siting Board reviewed an expected value forecast methodology. EEC (Remand) at 210. The Siting Board notes that the expected value methodology is akin to a forecast methodology previously reviewed by the Siting Council based on planning to a confidence level greater than 50 percent. Id. at 212; Boston Edison Company Decision (Phase I), 24 DOMSC 125, 279-286 (1992). In both decisions, the Siting Board found that planning to a confidence level greater than 50 percent may be appropriate for reliability purposes, but indicated that, in order to approve such planning, a proponent would be required to provide a cost/benefit analysis to support planning to a higher reliability. Id. In addition, the Siting Board noted that a proponent should consider the likelihood that all utilities within NEPOOL would agree to acquire resources based on a confidence level greater than 50 percent. Id.

Here, Altresco has not addressed either issue in proposing the Massachusetts expected value forecast as a base case forecast. In order to accept the Massachusetts expected value forecast as a base case forecast, further support would be required including a cost/benefit analysis. EEC (Remand) at 212.

Further, in regard to the Massachusetts expected value forecast, the Beach Association did raise a methodological concern regarding the Company's use of the regional and Massachusetts reference forecasts to develop a ratio for prorating results of the regional expected value forecast to derive the Massachusetts expected value forecast. We recognize that the ratio of Massachusetts peak load to regional peak load may vary between a deterministic forecast which represents one confidence level, and a probabilistic forecast, which reflects a range of confidence levels. However, the record contains no evidence that the Company's prorating approach resulted in a particular bias, upward or downward, in the Massachusetts expected value forecast.

Accordingly, the Siting Board finds that the Massachusetts expected value forecast is an acceptable forecast for use in an analysis of Massachusetts demand, but should not constitute a base case forecast.

With respect to the Massachusetts end-year CAGR forecast, the Company claimed that the long-term CAGR trend dampens the short-term pessimism of the Massachusetts reference forecast, while the Beach Association noted that the Company's long-term CAGR trend is high.

The Siting Board notes that the Company's Massachusetts end-year CAGR forecast shows higher peak load than the Massachusetts reference forecast for the entire 15-year span of the forecast period, excepting the end-year itself. Altresco might have provided a more balanced basis to develop the long-term trend of its forecast if it had used a range of later years in the forecast, rather than just the end-year.

Another technical consideration regarding the Massachusetts end-year CAGR forecast is the Company's choice of a CAGR format, in particular, to develop the long term trend. Recognizing that forecasters often use an end-year CAGR value as a means to characterize or label forecasts in general, the Company's choice of the CAGR format has intuitive appeal. However, the Company could have chosen a different forecast format, the most obvious alternative being a linear format. Here, because the Company used its selected trend format to interpolate annual load growth between two given load levels, the Company's choice of a CAGR format rather than a linear format was conservative with respect to the forecast of peak load for intermediate years of the forecast period, i.e., it tended to understate peak load relative to results that otherwise would have been obtained.

Thus, although the Company may have developed an unrepresentatively high long term trend by basing its Massachusetts end-year CAGR forecast solely on NEPOOL's Massachusetts load forecast for the end-year 2007, the Company was conservative in its choice of a CAGR trend rather than a linear trend for purposes of its Massachusetts need analysis. Therefore, on balance, the record does not support a conclusion that the Company's end-year CAGR methodology produced a trend-based forecast that is biased upward, as argued by the Beach Association.

Accordingly, based on the foregoing, the Siting Board finds that the Massachusetts end-year CAGR forecast provides an acceptable forecast for use in an analysis of Massachusetts demand.

With respect to DSM, the Company developed base, high and low DSM forecasts for Massachusetts, which in the case of the base and high case were consistent with the DSM forecasts in its regional need analysis, specifically by using the 1992 CELT forecast of DSM additions for Massachusetts as its high DSM forecast, and then discounting those additions by 25 percent and 50 percent in order to develop its base DSM forecast and low DSM forecast, respectively. In its review of the Company's regional need analysis, however, the Siting Board adjusted the Company's DSM forecasts, incorporating a smaller discount factor of 8.4 percent to derive the base DSM forecast.

In addition, the Siting Board has concerns with the Company's selection of its low DSM case. Despite the Company's testimony that engineering estimates, the basis of NEPOOL's current DSM projection, generally overpredict actual DSM savings by 30 to 50 percent (see Section II.A.3.c.), the Company's discount of DSM growth above 1991 levels by 50 percent appears to be somewhat arbitrary. Further, the Company provided no justification for assuming a lower low DSM case than the 1992 CELT low DSM case.

The Siting Board also has concerns with the Company's selection of the high DSM case. The Company provided no justification for assuming a lower high DSM case than the 1992 CELT high DSM case. NEPOOL's high and low DSM cases are not disaggregated by state. Thus, to adjust the Company's high and low DSM forecasts it is necessary to prorate NEPOOL's high and low DSM cases to Massachusetts based on the ratio of the adjusted base DSM forecasts in the Massachusetts and regional analyses.[102] Accordingly, for purposes of this review, the Siting Board finds that the Company's low DSM forecast should be adjusted

102 With respect to the demand forecasts incorporating the end-year CAGR methodology, the Siting Board adjustments to DSM require recalculation of the CAGR trend based on new values for DSM and resultant peak load in 2007 (see Section II.4.b.(1).(b), above). The new peak load values for 2007 with the adjusted DSM values are 12,402 MW under the base DSM forecast, 12,187 MW under the high DSM forecast and 12,731 MW under the low DSM forecast. The new CAGRs are 2.246 percent under the base DSM forecast, 2.126 percent under the high DSM forecast and 2.425 percent under the low DSM forecast.

to represent the 1992 CELT low DSM case, and the Company's high DSM forecast should be adjusted to represent the 1992 CELT high DSM case.[103]

Accordingly, the Siting Board finds that: (1) an adjustment of the Massachusetts base DSM forecast by 8.4 percent of the increment over 1992 levels is reasonable for purposes of this review; (2) the Company's Massachusetts high DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT high DSM case; and (3) the Company's Massachusetts low DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT low DSM case.

c. Supply Forecasts

(1) Description

The Company stated that it developed base, high and low supply forecasts for Massachusetts (Exh. AL-42, at 8). The Company stated that it developed its base Massachusetts supply forecast based on the 1992 CELT forecast of committed capacity that is owned or contracted by Massachusetts utilities, regardless of location, but excluded committed capacity in planned NUG projects not yet under construction (id. at 9).[104,105]

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103 The Siting Board notes that the 1992 CELT high and low cases are derived from the 1992 Resource Assessment, which was not published at the time the Company's regional need analysis was conducted.

104 The Company stated that it obtained Massachusetts committed capacity information directly from the 1992 CELT Report, except that it made adjustments based on other sources in order to: (1) reflect updated plant retirements and additions; (2) identify Massachusetts' 598 MW share of the Hydro-Quebec contract; and (3) identify Massachusetts' share of the PASNY allocations, amounting to 63 MW from 1995 to 1997 and 71 MW from 1998 to 2007 (Exhs. AL-42, at 8, 9, attachs. RLC-11, RLC-12, RLC-13; HO-JH-RR-2).

105 The Company stated that, if Massachusetts supply were based on nameplate capacity of power plants located in Massachusetts, the base case would reflect approximately 1,200 MW less capacity, resulting in earlier or larger Massachusetts need (Exh. AL-42, at 8).

With respect to interstate utilities supplying Massachusetts, the Company stated that the committed capacity of each such utility system was prorated to its Massachusetts service area based on the ratio of Massachusetts to systemwide summer peak load in 1991 (id. at 9).[106] Consistent with its regional need analysis, the Company indicated that it assumed a 22 percent reserve margin applicable to overall supply resources of Massachusetts utilities (id. at 13).

To develop the Massachusetts high supply case, the Company stated that it included 50 percent of the total capacity of uncommitted projects included by Massachusetts utilities in the 1992 CELT report,[107] as well as 50 percent of Massachusetts' share of a possible extension of the Hydro-Quebec contract beyond 2000 (id. at 10). The Company noted that it made no adjustment for the possibility that portions of two projects in the high supply case -- BECo's 306 MW Edgar project and the 150 MW Taunton Energy Center project -- could be sold to non-Massachusetts utilities (id. at 11).

To develop the low supply case, the Company assumed the unavailability of the Pilgrim Unit 1 nuclear facility beginning in 1995, and stated such a case was more than an academic possibility based on the Pilgrim facility's history of operating problems (id. at 10; Exh. JH-RR-2).

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106 The Company stated that the 1991 ratios for the three interstate utility systems -- New England Electric System ("NEES"), Eastern Utilities Associates ("EUA") and Northeast Utilities ("NU") -- are almost identical to the average projected ratios for these systems (Exh. HO-MN-10). The Company presented utility forecast information indicating that, between 1991 and 2001, the ratio of Massachusetts to systemwide summer peak load will decrease by 0.023 and 0.004 for NEES and NU, respectively, but will increase by 0.008 for EUA (id.; HO-MN-10(d)).

107 The Siting Board notes that the high supply analysis for the regional case and the Massachusetts case differs in one respect. The Massachusetts analysis assumes 50 percent of all of the uncommitted projects included in the 1992 CELT Report, class "L" and class "P", while the regional analysis assumes only 25 percent of the class "P" projects -- planned additions without regulatory approval (Exh. HO-MN-11). See Section II.A.3.d.(1), above.

In addition to presenting base, high and low Massachusetts supply forecasts, the Company presented a Massachusetts contingency analysis, consisting of nine contingencies (id. at 6-7).[108] Mr. La Capra stated that of the nine contingencies, there is an equal distribution between base, low and high case assumptions (Tr. JH-1, at 145).[109] The Company presented nine Massachusetts contingency supply forecasts, based on adjusting the Massachusetts base supply forecast to reflect each of the nine Massachusetts contingencies (id. at 11, 12).

(2) Positions of the Intervenors and Company's Response

The Beach Association argued that the Company developed Massachusetts supply forecasts that do not allow for any planned utility additions, and that this assumption is unrealistic and presents a low supply (Beach Association Supplemental Brief at 37). Further, the Beach Association argues that the assumption that Pilgrim will be out of service is too pessimistic, rendering the low supply case unreliable (Beach Association Supplemental Reply Brief at 31). Therefore, the Beach Association argues that the forecast presented by the

108 Altresco stated that the nine contingencies, based on the 1992 CELT Report except where noted, were as follows: (1) addition of 58 percent of planned but uncommitted NUG's (class "C"); (2) life extension of 25 percent of units currently scheduled for retirement; (3) increase in the required reserve margin by 2 percentage points; (4) decrease in the reserve margin by 2 percentage points; (5) retirement of 25 percent of units operating beyond NEPOOL guidelines for retirement, as shown in the 1989 CELT Report; (6) attrition of existing utility units as specified in the expected value case in the 1992 Resource Assessment; (7) attrition of existing NUGs as specified in the expected value case in the 1992 Resource Assessment; (8) the retirement of 33 percent of existing coal units operating beyond retirement guidelines and the assumption that 15 percent of utility coal plants are out of commission for retrofit at any one time; and (9) use of the expected value for Hydro Quebec Phase II rather than the nominal value (Exh. AL-42, at 12 and 13).

109 The Company presented, at the request of the Siting Board, two weighted need analyses, each weighing the supply case and contingencies to reflect other distributions rather than the equal probabilities as presented by the Company (Exh. HO-RR-89).

Company as the high supply case should be viewed as the base supply (Beach Association Supplemental Brief at 37).

The Company responded that the use of planned utility supply options as a base case is faulty as at least two of these units, the Edgar project and an MMWEC project are unlikely to be built (Company Supplemental Reply Brief at 5).

With respect to the Company's supply contingency analysis, the Beach Association argued that the Company applied its nine contingencies only to the Company base forecast, which as noted above includes no allowance for planned utility additions (Beach Association Supplemental Brief at 37). Further, the Beach Association argued that it is unrealistic to limit the analysis to a single contingency approach, and that it would have been appropriate to assess the probabilities of respective contingencies (id.). The Beach Association concurs that a weighted analysis of the contingencies should be considered, but cautions that justifications for the weights is a necessary component of any analysis (id. at 38).

(3) Analysis

As described above, the Company developed base, high and low supply forecasts that are somewhat consistent with those used in the regional need analysis. The Company and other parties generally adopted positions regarding the Massachusetts supply forecasts consistent with those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3., above.

Consistent with its findings regarding assumed reserve margins in the regional need analysis, the Siting Board finds that the Company's reserve margin for the years 1998 through 2000 should be adjusted as follows: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000.

Further, in its review of the regional need analysis, the Siting Board adjusted the Company's high supply forecast to include 66 MW of uncommitted capacity of NUG projects in the region that are existing or under construction. For purposes of the Massachusetts need analysis, it is reasonable to prorate the 66 MW adjustment based on the ratio of the Massachusetts reference forecast to the regional reference forecast. Under that approach, Massachusetts' prorated share of the 66 MW adjustment is 30 MW in each of the years 1996 through 2000. Accordingly, the Siting Board finds that the Massachusetts high supply forecast should be adjusted to include 30 MW of the uncommitted capacity of NUG projects that are existing or under construction.

The Beach Association suggests that the Company's low supply forecast, hypothesizing the loss of the Pilgrim unit, is a remote possibility. We note, as in our review of the regional need analysis, that the Company might have discounted its hypothesized loss of that nuclear unit to better reflect the limited probability of such loss. Nonetheless, loss of Pilgrim for an unusually long period was once experienced, and Massachusetts utilities own significant shares of other nuclear units which also potentially could be off line for long periods. Thus, the record does not support a rejection or adjustment of the Massachusetts low supply forecast.

Based on the foregoing, and consistent with its findings in the regional need analysis, the Siting Board finds that: (1) the Massachusetts base supply case represents a reasonable base supply forecast for the purposes of this review; (2) the Massachusetts low supply case represents a reasonable low supply forecast for the purposes of this review; and (3) the Massachusetts high supply case, as adjusted by 30 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review.

With respect to the Company's analysis of supply contingencies, the Siting Board notes that a presentation of supply forecasts based on a selection of such contingencies provides a means to assess the plausible range of variability in future supply. However, in EEC (Remand), the Siting Board stated its concern with compilations of contingency case capacity position results, stating that such compilations represent a weight-of-the-scenario approach without any explicit analysis of the relative probabilities of the scenarios.[110]

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110 At the request of the Siting Board staff, Altresco supplemented its contingency analysis to also provide a weighted analysis of its supply forecast and contingency case outcomes. The weighted analysis provides a more reliable basis for the Siting Board's (continued...)

Nevertheless, the Siting Board finds that the Company's Massachusetts supply contingency analysis provides an acceptable basis for assessing the potential range of Massachusetts utility capacity positions that might arise over the forecast period.

d. Need Forecasts

(1) Description

The Company presented 33 need forecast scenarios based on a comparison of its 11 demand forecasts, derived from the five methodologies and the three DSM forecasts, with its three supply forecasts, base, high and low (Exhs. AL-42, attach. RLC-17; HO-JH-RR-2(c); HO-JH-RR-8). Altresco also presented 99 additional need cases based on (1) adjusting the base supply forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing those nine adjusted supply forecasts with the 11 demand forecasts ("need contingency cases") (id.). Comparing all the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 170 MW of capacity would be: (1) 29 need forecasts, 88 percent, in 1996; (2) 31 need forecasts, 94 percent, in 1997; and (3) 33 need forecasts, 100 percent, in 1998 and beyond (id.). The Company indicated that a comparison of its base demand forecast -- the Massachusetts expected value forecast with Altresco's base DSM assumptions -- with its base supply forecast -- the 1992 CELT capacity forecast with updated information -- showed a need for over 170 MW in the early years of the proposed project, specifically: (1) 562 MW in 1996; (2) 903 MW in 1997; (3) 1,248 MW in 1998; (4) 1,605 MW in 1999; and (5) 2004 MW in 2000 (Exh. JH-RR-2 (c),(d),(e)). See Table 5.

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[110](...continued)

consideration of likely supply forecast variability. However, the Siting Board notes that providing estimated probabilities for an earlier selection of supply forecasts and contingency cases does not necessarily constitute a full and balanced representation, in probabilistic terms, of the actual range of possible outcomes. Although the Company's weighted analysis is a partial reflection of probabilistic techniques, it cannot substitute for a systematically designed probabilistic analysis such as that developed by NEPOOL in the 1992 Resource Assessment.

Considering the Company's need contingency cases together with its need forecasts, Altresco presented a total of 132 Massachusetts need cases (Exh. AL-42 at 15). The Company provided a summary of the results of its overall Massachusetts need analysis which indicated that the cumulative number and percentage of need cases that demonstrate a need for at least 170 MW of capacity would be: (1) 115 cases, 88 percent, in 1996; (2) 127 cases, 96 percent, in 1997; (3) 132 cases, 100 percent, in 1998 and beyond (Exh. HO-JH-RR-2(c)-(n)).

The Company indicated that 12 of its Massachusetts need cases correspond to need cases in the Company's regional need analysis, based on a comparison of the reference forecast, linear regression forecast, and CAGR regression forecast, whereby the reference forecast was combined with two DSM forecasts, and all were combined with the three supply forecasts (Exh. HO-JH-RR-7). The Company provided a summary of results which indicated that the cumulative number and percentage of such need scenarios that demonstrate Massachusetts need for at least 170 MW of capacity would be: (1) 9 cases, 75 percent, in 1996; (2) 10 cases, 83 percent, in 1997; and (3) 12 cases, 100 percent, in 1998 and beyond (id.). Comparing said results to the corresponding results for the regional need analysis -- (1) 6 cases, 50 percent, in 1996; (2) 6 cases, 50 percent, in 1997; and (3) 8 cases, 67 percent in 1998 -- the Company concluded that its analysis demonstrates that need will arise earlier in Massachusetts than in New England as a whole (Exh. HO-JH-RR-7).

The Company also presented two sets of additional calculations of Massachusetts need in response to requests of the Siting Board, including (1) alternative need calculations for most of the Company's need cases, based on assuming a 21 percent reserve requirement instead of a 22.5 percent reserve requirement in the years 1998, 1999, 2000 and 2001,[111] and (2) with respect to the three need forecasts that reflect high DSM and base supply,

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111 The Company provided recalculations for 110 need cases, including all 33 need forecasts and 77 of the need contingency cases (Exh. HO-JH-RR-8). The remaining 22 need contingency cases involve contingencies that already reflect higher or lower reserve margins, and thus were not included in the requested recalculations (id.).

alternative need calculations based on assuming the DSM levels in NEPOOL's high DSM forecast as an alternative to the high DSM levels in the Company's analysis (Exhs. HO-JH-RR-5; HO-JH-RR-8). Altresco stated that neither the change in assumed reserve margin nor the change in assumed high DSM levels significantly affects the timing of the first year of continuous need in the Massachusetts need analysis (id.). The Company further indicated that, assuming its base supply forecast in conjunction with the alternative high DSM levels, the first year of continuous need for at least 170 MW would remain 1997 under all three forecasts (Exh. HO-JH-RR-5).

With respect to the Company's compilation of capacity positions for the identified scenarios, the Beach Association argues that the 132 forecasts serve to compound errors in both the supply and demand methodology, and that the 132 forecasts could be collapsed into approximately nine reasonable forecasts based on the NEPOOL reference forecast (id.). Further, the Beach Association asserts that the 132 scenarios are meaningless, and should not carry any weight in proving Massachusetts need, as most are flawed and are derived from artificially separated contingencies (id. at 41; Beach Association Supplemental Reply Brief at 31).

(2) Analysis

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) the Company's Massachusetts base DSM forecast to reflect discounting of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels; (2) the Company's Massachusetts high DSM forecast to reflect the NEPOOL high DSM case; (3) the Company's Massachusetts low DSM forecast to reflect the NEPOOL low DSM case; (4) the Company's Massachusetts high supply forecast to include the 30 MW of uncommitted capacity of NUG projects that are existing or under construction; and (5) the Company's assumed reserve margin of 22 percent to reflect lower levels after 1997, specifically 21.5 percent for 1998, 21 percent for 1999, and 20 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has accepted the Massachusetts reference forecast as a base case in the long term, and has accepted the

Massachusetts expected value forecast, the Massachusetts end-year CAGR forecast, the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast as possible forecasts. While accepting the alternative forecasts to the Massachusetts reference forecast as possible forecasts, the Siting Board identified concerns with the alternative approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting Board addresses need based on two compilations of the Company's need forecasts as adjusted: (1) a compilation including only those need forecasts incorporating the reference forecast, and (2) an overall compilation including all need forecasts reflecting all three demand forecast methodologies.

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 170 MW in each year, from 1996 through 2000, is as follows:

Forecast	1996	1997	1998	1999	2000
Massachusetts reference forecast (9 cases)	5 (56%)	7 (78%)	8 (89%)	9 (100%)	9 (100%)
Alternative Massachusetts demand forecasts (24 cases)	24 (100%)	24 (100%)	24 (100%)	24 (100%)	24 (100%)
Total (33 cases)	29 (88%)	31 (94%)	32 (97%)	33 (100%)	33 (100%)

The capacity positions under the Massachusetts need forecasts, as adjusted, are shown in Table 6. Considered with the Massachusetts base DSM forecast, and the Massachusetts base supply forecast: (1) the Massachusetts reference forecast shows a need for 288 MW in 1997, and 553 MW by 1998; (2) the Massachusetts end-year CAGR forecast shows a need for 612 MW by 1997; (3) the Massachusetts expected value forecast shows a need for 785 MW by 1997; (4) the Massachusetts linear regression forecast shows a need for 921 MW by

1997; and (5) the Massachusetts CAGR regression forecast shows a need for 1,451 MW by 1997.[112]

In sum, 31 of the 33 Massachusetts need forecasts, including the 24 need forecasts that incorporate alternative Massachusetts demand forecast methodologies, show a need for at least 170 MW in 1997, 32 show a need for at least 170 MW in 1998, and 33 show a need for 300 MW in 1999 and 2000. In addition, seven of the nine need forecasts that incorporate the Massachusetts reference forecast show a need for at least 170 MW in 1997, eight such forecasts show a need for at least 170 MW in 1998, and all show a need for at least 170 MW in 1999 and 2000.

Accordingly, based on the foregoing, the Siting Board finds a need for 170 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1997. The Siting Board further finds that the Company's need analysis, including its need forecasts and contingency forecasts, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 170 MW of additional capacity clearly will occur earlier than New England's need for the same.

e. Other Factors

In addition to its analyses of need for capacity, Altresco argued that the proposed project would provide significant transmission benefits to the Massachusetts energy supply as a direct result of its location in the eastern section of the Rhode Island-Eastern Massachusetts-Vermont Energy Control Area ("REMVEC") (Company Initial Brief at 63). Altresco further argued that its proposed project would produce significant environmental benefits to the energy supply as a result of reduced air emissions due to displacement of more polluting generation. Consistent with our standard of review, the Siting Board

112 See n. 124

considers the Company's analyses in support of these benefits to determine if they are sufficient to establish need for the proposed project.[113]

(1) Transmission Benefits

Altresco argued that, because the Eastern REMVEC region is a net importer of power, it is wise to add electrical power generation in Eastern Massachusetts, thereby relieving constrained transmission facilities within the REMVEC area and at the interfaces[114] with neighboring transmission and distribution areas (Exh. AL-2, at 9-34 through 9-35). Altresco asserted that relieving such constrained transmission improves transmission reliability and voltage regulation, and allows more transmission to be available for both utility and non-utility projects (id.).

Altresco stated that the transmission problems in the Eastern REMVEC area relate to shortages of both "real power" and "reactive power" which result from insufficient generation capacity in the vicinity of local load centers (Exh. AL-15, at 1-2). Additionally, the Company stated that reactive power, unlike real power, cannot be efficiently transmitted over long distances (id.).[115] Altresco provided an excerpt of a 1990 study conducted for

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113 The Siting Board notes that the Company presented these analyses in response to our standard of review for need prior to the SJC decision in City of New Bedford, supra. In EEC (Remand), we revisited our standard of review for need. In that decision, the Siting Board found that need could be established on reliability, economic efficiency, or environmental grounds directly related to the energy supply of the Commonwealth. See Section II.A.1.c., above.

114 Interface(s) refer to those segments of major transmission lines which link energy control areas such as the eastern REMVEC area to other areas of transmission supply and distribution.

115 The Siting Board notes that alternating current ("AC") transmission lines carry "apparent power" (measured in units of volt-amperes ("VA")) -- which is a complex unit of power that reflects the existence of both "real power" (measured in units of watts ("W")) and "reactive power" (measured in units of volt-amperes-reactive ("VARS")). "Real power" refers to that component of the "apparent power" which performs useful work, i.e., the turning of a motor's shaft, illumination from a light (continued...)

the New England Cogeneration Association which concluded that the Eastern REMVEC region will continue to experience significant capacity deficiencies over the next decade even if all existing, committed, and uncommitted non-utility generators proposed in the region are assumed to be operational (Exh. HO-MB-9).[116]

Altresco argued that in the absence of sufficient local generating capacity, the eastern REMVEC area utilities have had to rely upon two strategies to ensure the availability of an adequate level of real and/or reactive power: (1) the installation of additional capacitors on the transmission system to increase the amount of reactive power available to the local area, and (2) the operation of certain local power plants as "must run" units, even though these power plants actually have higher dispatch prices than some dispatchable plants (Company Initial Brief at 64). Altresco added that such strategies incur added costs which could be avoided by the construction of new generating capacity such as the proposed facility (Exh. AL-15,
at 2).

Specifically, Altresco's witness, Mr. La Capra, testified that the proposed facility would supply approximately 105 MVARS of reactive power (id.). Mr. La Capra also testified that, without the proposed facility, the least costly correction to enhance the reactive power supply would be the installation of series capacitors on the power lines serving the affected area. As a specific alternative, Altresco indicated that a capacitor installation capable of providing fifty percent of the reactive power provided by the proposed facility, i.e. 52.5 MVARS, would cost approximately $787,500 (id.; Tr. 12, at 4-5). Altresco argues that the elimination of the need for such an expenditure for additional reactive power support

[115](...continued)
bulb, heat from a toaster, etc. "Reactive power" refers to that component of the "apparent power" which is necessary for the proper operation of some devices -- such as establishing necessary magnetic fields in a motor or transformer -- enabling it to efficiently utilize the "real power" component to do the useful work.

[116] Altresco provided the Siting Board with a list of all other generating projects either under construction or proposed for the eastern REMVEC area (Exh. HO-MB-9).

-- a result of operation of the proposed facility -- represents a reasonable estimate of the minimum economic advantage attainable from the plant in MVAR enhancement (Company Initial Brief at 65).

Altresco also quantified the energy cost savings associated with changing the status of existing generating units in eastern REMVEC from "must run" to "dispatchable" by performing an analysis which assumed that 170 MW of Boston Edison Company's New Boston 1 & 2 units would be switched from "must run" to "dispatchable" status as a result of the construction and operation of the proposed facility (Exh. AL-15, at 3). Specifically, Altresco compared the results of a hypothetical 1996 dispatch analysis assuming generation of 140 MW by New Boston 1 & 2 units with results of a 1996 "must run" dispatch analysis based on operation of New Boston 1 & 2 units at their full capacity of 310 MW (id.).[117] Based on this comparison, Altresco asserted that, beginning in 1996, the net savings realized as a result of Altresco's proposed facility coming on-line would total $304 million over 20 years, and that this amount represented a conservative figure (id.).

The record demonstrates that the proposed project would provide power reliability enhancement in the eastern REMVEC area. In addition, Altresco's analysis reasonably demonstrates that such reliability enhancements, alone or in conjunction with other reliability enhancements that may be possible in the eastern REMVEC area, could provide economic benefits to the energy supply by eliminating the need for the installation of series capacitors and/or the revision of dispatch status of other more costly power plants in the area.

The Siting Board notes, however, that in Turners Falls, the Siting Council found that transmission-system-related benefits must be significant and carefully documented in order to demonstrate benefits to Massachusetts as part of an analysis of need (18 DOMSC at 159).

The Siting Board notes, further, that in Enron, the Siting Council noted that, while the project in that case was to be located in the eastern REMVEC area, Enron had provided only general non-project-specific information regarding the potential transmission benefits of the

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117 Both 1996 dispatch analyses assumed operation of the proposed facility at 170 MW (Exh. AL-15, at 3).

proposed project, and had failed to provide detailed load flow analyses which would allow the Siting Board to determine the level of reliability benefits associated directly with the project (23 DOMSC at 68-69).

Here, while the proposed project is located in the eastern REMVEC area, Altresco has, with the exception of specific and quantifiable reactive power replacement data, provided only general, non-project-specific information regarding the potential transmission benefits of the proposed project.

While Altresco has demonstrated that the addition of generic electric generation capacity in the eastern REMVEC region would likely improve, to some degree, the reliability of the transmission system in that region, Altresco has failed to provide detailed load flow analyses which would enable the Siting Board to determine the significance of any reliability benefits associated directly with the proposed project. The Siting Board notes that even in an area which is generally acknowledged to have transmission problems, as is the case with the REMVEC area, the degree to which a proposed new facility will alleviate those problems may be strongly dependent upon the specific location, technical, and operational details of that facility.

Further, with respect to the potential economic benefits to the energy supply associated with the potential dispatch status changes of other area facilities, the Company did not clarify how such an annual displacement of 170 MW or more of existing generation would in fact occur, nor how any such 170 MW reduction in generation would be distributed between existing units. Also, given the Company's own submission of evidence indicating that the eastern REMVEC region will continue to experience long-term capacity deficiencies even if all existing committed and uncommitted non-utility generators proposed in the region are assumed to be operational, it is unclear whether a dispatch change from "must run" to "dispatchable" for existing units would actually occur. Finally, with respect to the Company's claims regarding eastern REMVEC area reactive power shortages, the record demonstrates that Altresco's information indicating that such a shortage exists in the eastern REMVEC area is inconclusive. Accordingly, the Siting Board finds that the Company has failed to establish need for the proposed project based on transmission system reliability grounds.

(2) Air Quality Benefits

Altresco argued that the proposed project would produce substantial environmental benefits to both the Massachusetts and New England energy supply in the form of reduced air pollutant emissions which would result from the displacement of higher emission-generating power sources by the operation of the proposed project, as well as displacement of emissions associated with steam production at GE by steam sales from the proposed project (Exh. HO-RR-43; Company Initial Brief at 66-67).[118]

To demonstrate environmental benefits realized from the displacement of existing sources of air emissions, the Company presented a dispatch analysis comparing emissions of seven major pollutants associated with the combustion of fossil fuels both with and without the proposed project: (1) sulphur dioxide ("SO_2"); (2) nitrogen oxides ("NOx"); (3) particulates ("PM-10"); (4) carbon monoxide ("CO"); (5) volatile organic compounds ("VOCs"); (6) carbon dioxide ("CO_2"); and (7) methane (Exhs. HO-MB-18 and attachments; AL-40).[119] Based on the results of this analysis, Altresco claims that the operation of the proposed project would significantly reduce regional emissions of SO_2, NOx, VOCs, CO,

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118 The Siting Board notes that benefits which relate directly to the reliability, cost or environmental impact of the energy supply of the Commonwealth include, but are not limited to, economic efficiency benefits to ratepayers, electric transmission benefits, emissions offsets in the region or at the steam host, and gas/oil swaps with local gas distribution companies. The Siting Board also notes that other benefits not related to the energy supply, while not relevant to the review of need for a proposed project, may still be considered in respect to G.L. c. 164, §§ 69I and 69J which require that proposals to construct energy facilities are consistent with the current health, environmental protection and resource use and development policies as adopted by the Commonwealth.

119 The Company analyzed dispatch effects for each of the ten years 1995 through 2004, for 2009, and for 2014, and provided interpolated values for the remaining years (Exh. HO-MB-18, attachment c).

PM-10, and CO_2, and slightly increase methane emissions to the region beginning immediately in 1995 and continuing through the year 2014 (id.).

Altresco added that, for Massachusetts specifically, operation of the proposed facility would reduce emissions of SO_2, NOx, CO and PM-10, but increase emissions of VOCs, CO_2 and methane (id.).[120]

Altresco additionally stated that its current steam sales agreement with GE would provide for delivery of approximately 16 percent of GE's total steam generation requirements, and as such would reduce GE's existing combustion of fuel oil for steam production by approximately 81,000 barrels per year while producing the same total amount of steam (Exh. HO-MB-5). The Company provided estimates of the annual emissions reductions at GE's existing steam production plant that would result from GE's utilization of Altresco-produced steam. Estimated reductions include 72 tons of NOx, 228 tons of SO_2, 14 tons of particulates, 9 tons of CO, 1 ton of non-methane hydrocarbons, 35,900 tons of CO_2 and .2 tons of methane (Exh. HO-RR-43).

The Siting Council previously held that a project proponent must provide full documentation of its assumptions pertaining to environmental benefits associated with the dispatch of generation capacity. Enron, 23 DOMSC at 71; West Lynn, 22 DOMSC at 48; MASSPOWER, 20 DOMSC at 388.

In Enron, 23 DOMSC at 69-73, the Siting Council reviewed the most comprehensive analysis to date of environmental benefits resulting from dispatch effects of a proposed gas-fired facility. In that dispatch analysis, annual air emissions changes were estimated for four selected years spanning a 20-year period, assuming three alternative expansion plans for meeting regional capacity deficiencies Id., at 45-48, 70. The Siting Council found that the

120 The Company also provided four alternative emissions analyses which included alternative projections regarding load, fuel prices, and generation mix (Exh. HO-RR-73 and attachments). Altresco noted that the results of these analyses indicate that the total emissions savings to New England are not especially sensitive to assumptions regarding projected demand, fuel prices, or future supply mix (id.). Altresco further noted that the results of these analyses indicate that the total estimated emissions reduction savings in Massachusetts would be more sensitive to input assumptions (id.).

proposed project in that review would provide Massachusetts with environmental benefits related to net changes in air emissions from generating facilities in Massachusetts. Id., at 73.

In a more recent decision, the Siting Board reviewed a five-year dispatch analysis, which assumed that energy requirements would be met by currently claimed committed capacity and, as necessary, new oil-fired combustion turbine units. EEC (Remand), at 94-104. Based on the applicant's dispatch analysis, the Siting Board found that the proposed project in that review likely would provide short-term air quality benefits for Massachusetts. Id., at 101. The Siting Board identified shortcomings of the dispatch analysis in that review for addressing the potential for long-term air quality benefits, including: (1) the failure to reflect the potential addition of other presently uncommitted base load capacity as part of assumed generation expansion, rather than just oil-fired combustion turbine units; (2) the assumption of constant emission rates over time, in pounds per MMBtu, for generating units in the analysis; and (3) the failure to reflect any significant amounts of potential retirement of existing generating units, beyond one scheduled retirement of a 28 MW unit, over the five-year period of analysis.[121] Id., at 101-102.

Here, Altresco has provided the Siting Board with a comprehensive analysis of dispatch effects on state and regional emissions for the period 1995-2014. 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 for the Siting Board to be able to evaluate whether there would be significant dispatch related benefits to the Massachusetts energy supply specific to operation of the proposed project.

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[121] In addressing the potential for long-term air quality benefits as a result of the applicant's project, EEC (Remand), considered whether the changing regional supply mix, with operation of the applicant's project, would be likely to ensure (1) avoidance or minimization over time of any emissions increases and (2) maintenance over time of the initial displacement of intermediate and peaking units that would result from the applicant's project (at 101).

For the purposes of assessing environmentally based need in Massachusetts, the Siting Board here focuses primarily on Altresco's calculations of the net impact that the proposed project would have on the total emissions from generating facilities located in Massachusetts. Altresco's analysis indicates that, under a range of realistic generation expansion scenarios, the operation of the proposed project would clearly reduce the net emissions in Massachusetts of four of the seven pollutants analyzed: SO_2, NOx, CO and PM-10. These net reductions, however, are offset to a degree by the higher net Massachusetts emissions of VOCs, CO_2 and methane.[122] However, the Siting Board notes that emissions of two pollutants which are of greatest concern to regional acid rain and ground-level ozone problems, i.e., SO_2 and NOx, would be reduced significantly by the operation of the proposed project.

Thus, the Company's dispatch analysis, considering on balance the criteria and other pollutants identified therein, demonstrates that the proposed project would, at a minimum, provide short-term air quality benefits for Massachusetts based on its displacement of existing generation and associated emissions of several important pollutants.

The Siting Board notes that, while the Company's dispatch analysis demonstrates that the proposed project would provide short-term air quality benefits for Massachusetts based on its initial displacement of existing generation and associated emissions, it is unclear that the benefits of such displacement would be permanent. First, the Company's analysis allows the displaced generation to be increasingly redispatched over time with continued load growth. Second, the Company's analysis assumes that the emissions rates from respective units in the analysis, in pounds per MMBtu, remain constant over time. Third, the analysis includes no explicit assumptions or scenarios demonstrating a potential for holding Massachusetts emissions to current or lower levels through planned or accellerated retirement of existing generation.

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122 Recognizing that a significant increase in levels of CO_2 is of possible concern regarding climatic changes on a global scale, the Siting Board notes that the net regional reduction in CO_2 is likely of substantially greater importance than the net Massachusetts increase in CO_2 emissions.

The Siting Board recognizes that load growth represents a given for purposes of the Company's dispatch analysis, and that the analysis must assume dispatch of available capacity to meet load growth over time. However, in the EEC (Remand) at 102, the Siting Board questioned the assumption of constant unit emission rates over time and the assumption of continued dispatch over time of older generation with high emissions rates as part of any dispatch analysis encompassing more than a short-term period. However, while finding in that decision that the applicant's dispatch analysis failed to demonstrate long-term air quality benefits, the Siting Board noted that, to the extent that the applicant's project would in whole or in part replace existing generation that potentially will be permanently retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation.[123]

With respect to the displacement of GE steam production and associated emissions as a result of steam sales from the proposed project, the Siting Council previously has considered the potential for applicants' cogeneration projects to provide air quality benefits to Massachusetts based on net emissions reductions at the site, i.e., expected reductions in an existing steam host's steam production facility emissions that are greater than expected total emissions from the applicant's cogeneration project. Altresco-Pittsfield, 17 DOMSC at 368; MASSPOWER, 20 DOMSC at 329-330. In both previous reviews, applicants demonstrated that their cogeneration projects would result in a net reduction in SO_2 emissions but a net increase in NOx emissions; in Altresco-Pittsfield, the Siting Council found that the SO_2 reduction outweighed the NOx increase and that the applicant's cogeneration project therefore would provide environmental benefits based on displacement of steam production facility emissions. Id.

Here, Altresco has provided documentation indicating the emissions reductions that would be realized by the proposed project's steam sales agreement with GE, and GE's

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123 The Siting Board recognizes that similarly favorable long-term air quality results may also be achieved through a combination of (1) implementing new base load generation with low emissions and (2) implementing new emissions controls at existing generating units capable of reducing emissions rates in pounds per MMBtu from such units.

resultant reduction in fuel oil requirements to create the same amount of steam. In comparing these reductions with the emissions expected from the proposed project, there would be an annual reduction of approximately 189 tons of SO_2, but an annual increase of approximately 61 tons of NOx, 14 tons of PM-10, and 9 tons of CO. While air quality in the Lynn area would benefit from reduced levels of SO_2, it is clear that ground level ozone would be adversely affected by a net increase in emissions of NOx.

Accordingly, the Siting Board finds that Altresco has demonstrated that the proposed project would provide short-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts. However, the Siting Board finds that Altresco has not demonstrated that the proposed project would provide long-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts. Finally, while Altresco has demonstrated that the proposed project would reduce SO_2 emissions in the Lynn area, based on displacement of existing GE steam production operations as a result of its steam sales agreement with GE, the levels of other pollutants would increase. Therefore, the Siting Board finds that Altresco has not demonstrated a significant improvement in air quality in Lynn due to the displacement of GE steam production.

Accordingly, the Siting Board finds that Altresco has failed to establish that the proposed project is needed on environmental grounds.

5. Conclusions on Need

The Siting Board has found that Altresco has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPAs. The Siting Board further has found that there will be a need for 170 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 or later. The Siting Board also has found that Altresco has established that, beginning in 2000, New England will need 170 MW of additional energy resources from the proposed project for economic efficiency purposes. Further, the Siting Board has found that there will be a need for 170 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1997. Finally, the Siting Board has found that the Company has failed to establish need for the proposed project based on transmission system reliability grounds or environmental grounds.

Based on the foregoing, the Siting Board has found that the Company's need analyses demonstrate that Massachusetts' need for 170 MW of additional capacity will occur earlier than New England's need for same. Given the demonstration of earlier need in Massachusetts than New England, it is clear that, for all years in which there will be a regional need for the proposed project, i.e., for the years 2000 and beyond, the proposed project would provide a necessary energy supply for the Commonwealth.[124] The proposed

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124 The Siting Board hereby takes administrative notice of recent electric forecast cases concluded by the DPU and the Siting Council. In Fitchburg Gas and Electric, 24 DOMSC 322 (1992), the Siting Council approved a forecast showing that in the summer of 1995, the last year of its forecast, Fitchburg Gas and Electric Company would have a total capacity of 102.10 MW, resulting in a surplus of 19.1 MW over its "capability responsibility" of 83.0 MW and a surplus of 26.2 MW over its summer peak load of 75.9 MW (at Table 3 and Table 4). In Boston Edison Company (Phase I), 24 DOMSC 125 at 303 (1992), the Siting Council found that Boston Edison Company would have surplus capacity of 149 MW in 1996 and 120 MW in 1997, the last year included in its forecast. In Eastern Utilities Associates, DPU 92-214, (1993), the Department approved a forecast showing that for 1996, the last year in its forecast, Eastern Utilities Associates would have a base case summer peak load surplus of 197.6 MW. In Commonwealth Electric Company\Cambridge Electric Light Company, DPU 91-234 (1993), the Department approved a forecast indicating that the Cambridge Electric Light and Commonwealth Electric Companies would have a supply surplus through the year 2000, specifically a surplus of 116 MW in the winter of that year (at Table 3). The Department and the Siting Council approved settlements in four other proceedings filed pursuant to 220 C.M.R. § 10.00 et seq., the Integrated Resource Management Regulations. However, these settlements do not establish precedent nor does the Department's acceptance of the settlements constitute a determination or finding on the merits of any aspect of these proceedings. See Fitchburg Gas & Electric Co., D.P.U. 92-181, at 22 (1993); Boston Edison Company, D.P.U. 92-265 (1993); Western Massachusetts Electric Company\Northeast Utilities, D.P.U. 92-88, at 9-10 (1992); Massachusetts Electric Company\New England Power Company, EFSC 91-24\D.P.U. 91-114, at 5 (1991).

project on-line date, however, is 1996. Thus, the Siting Board must evaluate whether the project is needed beginning in the year 1996.

In EEC (Remand) at 188, the Siting Board noted that an applicant could establish that a regional capacity surplus might not be available to meet a Massachusetts capacity deficiency as a result of transmission or other reliability constraints. The Siting Board further noted that an applicant could establish that reliance on a regional capacity surplus would be contrary to providing a necessary energy supply at the lowest possible cost with the least environmental impact. (See n.18).

However, this recognition was set out in EEC (Remand) after the record in this proceeding was fully developed. Thus, in this case, a record on this issue has not been developed. The record shows that for the years 2000 and beyond there is a need of 170 MW or more for both Massachusetts and the region. However, the record is unclear regarding the ability of Massachusetts utilities to acquire surplus supplies from out-of-state providers in years in which there is a Massachusetts deficiency of 170 MW or more and a regional deficiency of less than 170 MW or a regional surplus. Therefore, based on the record, the Siting Board is unable to determine that the proposed project is needed to provide a necessary energy supply for the Commonwealth prior to the year 2000.

The Siting Board notes that a similar disparity occurred between the timing of Massachusetts and regional need in a previous review of a proposed generating facility. In EEC (Remand) at 266-267, a review of a proposed 300 MW coal-fired facility, the Siting Board found that there was a need for at least 300 MW of additional energy resources in New England for reliability purposes beginning in 2000 and a need for at least 300 MW of additional energy resources in Massachusetts for reliability purposes beginning in 1998. In that decision, the Siting Board determined that it was appropriate to require the Company to submit PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. The Siting Board found that the amount of facility output subject to signed and approved PPAs that would be sufficient to establish Massachusetts need would depend on other factors which contribute to Massachusetts need as well as the size and type of facility. Thus, the Siting Board found that the submission of (1) signed and approved

PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which is the result of a competitive resource solicitation process beginning in 1993 or beyond and which is approved pursuant to G.L. c. 164, sec. 94A will be sufficient evidence to establish that the proposed project will provide a necessary energy for the Commonwealth. See, EEC (Remand) at 268.

Here, the proposed facility is a 170 MW, gas-fired facility. Altresco has a signed and approved PPA which includes capacity payments with ComElectric, a Massachusetts utility, for 25 MW. In addition, Altresco is the sole award winner of BECo's RFP 3 solicitation for 132 MW. The Siting Board has found that signed and approved PPAs which include a capacity payment constitute prima facie evidence of the need for additional energy resources for reliability purposes. See, e.g., NEA, 16 DOMSC at 358. With the 25 MW contract which includes capacity payments, 14.7 percent of the facility output is needed for reliability purposes, and, if the BECo contract is signed, 92.3 percent of the facility output would be needed. However, as noted above, uncertainties exist as to when and if the PPA with BECo will be signed and approved. See Section II.A.2., above.

As noted above, the amount of facility output subject to signed PPAs sufficient to establish Massachusetts need would be dependent on the size and type of facility. In EEC (Remand), in comparing the proposed project to technology alternatives, the Siting Board found that the proposed project would be superior to all technology alternatives reviewed with respect to providing a necessary supply with a minimum impact on the environment at the lowest possible cost (at 165). However, the Siting Board also found that the natural gas combined-cycle alternative would offer greater environmental benefits to the energy supply relative to the proposed project and that the proposed project would offer greater cost and reliability benefits to the energy supply relative to the natural gas combined-cycle alternative. Id.).

Here, in comparing the proposed project to technology alternatives, the proposed project is superior to all technology alternatives reviewed with respect to providing a necessary supply with a minimum impact on the environment at the lowest possible cost. Further, the proposed project would offer greater environmental, cost and reliability benefits to the energy supply relative to the technology alternatives examined (See Section II.B.6., below). In addition, this project has established need on reliability grounds beginning in 2000 and need on economic efficiency grounds beginning in 2000 or later. Finally, we note that this is a 170 MW facility, while the proposed EEC facility is 300 MW.

Here, in light of the need for the proposed project beginning in the year 2000 on reliability grounds, the Siting Board finds that submission of (1) a signed and approved contract with BECo for 132 MW, or (2) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, will be sufficient to establish that the proposed project will provide a necessary energy supply for the Commonwealth. Altresco must satisfy this condition within four years from the date of this conditional approval. Altresco will not receive final approval of its project until it complies with this condition. The Siting Board finds that, at such time that Altresco complies with this condition, Altresco will have demonstrated that the proposed project will provide a necessary energy supply for the Commonwealth.

B. Alternative Technologies Comparison

1. Standard of Review

G.L. c. 164, § 69H, requires the Siting Board 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, § 69J, requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing, other site locations;[125] (b) other sources of electrical power or gas, including facilities which operate

[125] The issue of alternative site locations is addressed in the review of the Company's Site Selection Process (see Section III.B).

on solar or geothermal energy and wind or facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

In implementing its statutory mandate, the Siting Board requires 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.[126] EEC (Remand), at 65. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Board determines whether the project offers power at a cost below the purchasing utility's avoided cost. Id.; Altresco, 17 DOMSC at 370-378; NEA, 16 DOMSC at 360-380.

2. Identification of Resource Alternatives

The Company asserted that it has demonstrated through analyses that there is both a regional need and a Massachusetts need for at least 170 MW of new capacity on reliability and economic efficiency grounds beginning in 1996 (Exh. AL-40, at 2). To address an identified need for at least 170 MW of additional energy resources, Altresco proposes to construct a nominal 170 MW combined-cycle, gas-fired cogeneration facility in Lynn, Massachusetts which would commence commercial operation in 1996 (id. at 5).[127]

Altresco stated that it examined alternate approaches to addressing the identified need, including both conventional and non-conventional technologies (id. at 2).[128] The Company stated that it evaluated the alternative energy resources in terms of size, reliability, technological maturity, construction time-frame, siting/permitting feasibility, fuel availability, and compatibility with cogeneration and non-utility generation (id. at 2). Altresco indicated

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126 The Siting Board includes in its review site-specific impacts of both the proposed project and each alternative at the proposed site. EEC (Remand), at 65, n.106.

127 The Siting Board notes that it has found that there is a New England need for at least 170 MW of new capacity beginning in the year 2000. See Section II.A.3.e.(3).

128 Altresco asserted that its technology analysis included all of the technology options enumerated under G.L. c. 164, Section 69J (Company Supplemental Brief at 15).

that any alternative energy source would also have to satisfy both the region's need for power and GE's need for steam (Exh. HO-PA-1).

The Company stated that it did not consider in detail technologies that would provide too little capacity at the proposed site to meet the identified need, such as municipal solid waste, biomass, and wind turbines, nor technologies that would provide more generating power than required, such as nuclear fission (Exh. AL-40, at 2).[129] Further, the Company stated that it did not consider technologies with an immature development status such as photovoltaic cells, compressed air energy storage, fuel cells, nuclear fusion and battery storage (id. at 3).[130] The Company also stated that wind turbines and photovoltaics would be unable to supply a steam host (Tr. 13, at 16).[131]

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129 The Company provided documentation from the 1992 CELT Report listing the existing and planned utility and non-utility generating facilities in New England and the respective largest facilities by fuel type (Exh. HO-PA-1). For alternative resources the listing included: (1) municipal solid waste: 65.6 MW; (2) biomass/coal: 75 MW; (3) methane: 11 MW; (4) wind turbines: .21 MW; (5) wood: 53 MW; and (6) photovoltaic cells: .01 MW (id.). Altresco indicated that the alternative facilities listed in the 1992 CELT Report were among the largest New England facilities of each type found, representing realistic upper limits of their capacity (Tr. 13, at 14 and 15). The Siting Board notes that the capacities cited by the Company are not necessarily reflective of the capacity potential for these technologies.

130 Altresco stated that it can only pursue known and proven technologies, as it must have a certain lead time from the planning stage to commercial operation (Tr. 13, at 76).

131 Altresco stated that it eliminated from its consideration technologies which could not fit within the property site (Exh. HO-PA-1). The Company noted that the Altresco site would occupy 5.7 acres on the GE River Works site (Exh. AL-2, at 1-1). Altresco's witness, Dr. Hill reported that, as GE cannot identify any surplus properties on the River Works site, there is no additional property available for the Altresco proposed project (Tr. 13, at 46). The Company stated that the appropriate frame of reference for evaluating alternative energy resources for a cogeneration project is site specific, and that, therefore, any alternative resources must be able to be built on this 5.7 acre parcel of land (Exh. HO-PA-1). Altresco stated that non-conventional resources identified in this proceeding, such as wood, biomass, coal and municipal solid waste would require large areas of storage capability (Tr. 13, at 16).

(continued...)

In regard to DSM, the Company asserted that it has already incorporated all presently identified cost-effective DSM in the need analyses (Exh. AL-40, at 4). Altresco stated that there is no basis for assuming higher levels of DSM, and further, although there may be a technical potential for additional DSM resources, said resources would be non-cost effective (Exh. HO-PA-2).[132]

Based on these considerations, the Company stated that it identified five alternatives that are capable of meeting the identified need, in addition to the proposed Altresco proposed project (Exh. AL-40, at 3). Specifically Altresco identified: (1) a dual-fuel, combined-cycle plant with an interruptible 10 month gas supply and a distillate oil backup ("gas/oil GTCC alternative"); (2) a distillate oil-fired, combined-cycle plant ("oil-fired GTCC alternative"); (3) a circulating fluidized bed coal plant ("CFB alternative"); (4) a conventional pulverized coal steam unit ("pulverized coal steam alternative"); and (5) a residual oil-fired steam plant ("residual oil steam alternative") (id.). The Company reported that it had also considered coal gasification as an alternative technology but rejected it at an early stage due to the difficulty in siting a facility in Massachusetts, problems with remediation, and the Company's recognition that it did not have the environmental advantages of the selected technologies (Tr. 13, at 24 and 25).

Altresco asserted that a combined-cycle gas facility, such as the proposed project, would be the highest and best use of the River Works site for generation purposes and to provide steam to GE (id. at 22). Further, the Company stated that the particular characteristics of the GE site are especially suited to the proposed project from an

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[131](...continued)
However, the Siting Board notes that for the purposes of this review, the Company included coal-fired and oil-fired alternatives which would require more than the available space in its technology comparison analyses.

[132] The Siting Board notes that the standard of review requires the consideration of the reduction of load management to be included in the analysis of need and in EEC (Remand) at 56, the Siting Board found that an analysis of load management as an alternative to the planned activity is not required by the statute.

environmental standpoint when compared to the listed alternatives (Company Supplemental Brief at 35).

Finally, the Company stated that all of the selected technology alternatives were compared on the same level of net electric output, 170 MW, and steam supply, 55,000 lbs/hr to GE (Exh. AL-40, p. 12). The Company indicated that all generic data requirements were obtained from the 1992 GTF, which included availability and heat rates (id., Exhs. HO-PA-5; AL-40, attach. RLC-2 and attach. RLC-6).[133, 134]

Altresco indicated that each alternative was assigned a projected availability rate, of which the Altresco proposed project has the highest projected availability at 92 percent (Exh. AL-40, attach. RLC-2 and attach. RLC-6). The Company stated that this availability is reasonable since such an availability rate currently is maintained at the Altresco Pittsfield facility, and the two facilities have similar technologies (Tr. 13, at 115). The alternative technologies comparison is based on the following availability factors: gas/oil GTCC and oil-fired GTCC alternatives, 86.8 percent; CFB alternative, 83.5 percent; pulverized coal steam alternative, 81.4 percent; and residual oil steam alternative, 84.7 percent (Exh. AL-40, attach. RLC-8). Further, the Company indicated that each alternative was assigned a heat rate, of which the proposed Altresco project had the lowest rate of 8,600 Btu/Kw-hr (id.). The alternative technologies comparison is based on the following heat rates: gas/oil GTCC and oil-fired GTCC alternative, 8,904 Btu/kW-hr; CFB alternative, 10,077 Btu/kW-hr; pulverized coal steam alternative, 10,402 Btu/kW-hr; and residual oil steam alternative, 9,712 Btu/kW-hr (id.).

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133 The Company stated that the GTF Report is published annually and is appropriate for use in this analysis since it focuses solely on the New England region and is up-to-date (Exhs. AL-40, at 6; HO-PA-5).

134 The Company utilized project specific data for the proposed facility heat rate and availability (Tr. 13, at 102, 115).

3. Environmental Impacts

The Company compared the alternative technologies and proposed project with respect to environmental impacts in the areas of air quality, fuel transportation, land use and fuel storage, water use, and solid waste. The Siting Board reviews the Company's analysis of environmental impacts below.

a. Air Quality

The Company presented an analysis of the air quality impacts of alternative technologies which would be fueled by one of three types of fuel: gas, coal and oil (Exh. AL-40). The Company stated that the alternatives using oil are assumed to use very low sulfur oil (.05 percent oil), the same oil proposed for the proposed project,[135] and the coal-fired alternatives are assumed to use 1.8 percent sulfur coal (id. attach. RLC-3; Exh. PA-23). The following chart depicts the estimated emissions from the proposed project[136] and each of the generic alternatives in tons per year ("tpy"):

135 The Company expects to be permitted by the DEP to use very low sulfur oil for up to five days a year for the proposed project's back-up oil supply (Exh. HO-E-1, at 5-3).

136 The National Ambient Air Quality Standards ("NAAQS") limit the total ambient level of six pollutants, referred to as criteria pollutants: (1) SO_2; (2) PM-10, (3) NOx; (4) CO; (5) "O_3" and; (6) lead (Exh. HO-E-4 at 3-2). Volatile organic compounds ("VOC") are regulated as a precursor to ozone (id., at 3-4). (See Section III.C.2.a., for a further discussion of air quality).

TABLE 7

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2
(TPY)

Air Emissions (TPY)	Altresco	Gas/oil GTCC	Oil-fired GTCC	CFB	Pulverized Coal Steam	Residual Oil Steam
SO_2	39	77	288	1,441	1,450	735
NOx	133	158	201	940	1,072	919
PM-10	63	90	253	113	114	110
CO	130	129	138	814	315	184
VOC	31[137]	20	58	38	38	31
CO_2	699,490	727,040	966,840	1,278,060	1,286,220	1,029900
Lead	null	0.1	0.6	0.2	.02	null

Note: See Section II.B.2., explaining the source of the underlying assumptions for the proposed project and alternatives.

source: Exhs. HO-PA-22; HO-RR-86

Altresco stated that the generic combined-cycle units included SCR pollution control equipment and further, that the emissions levels for the CFB alternative, pulverized coal steam alternative and residual oil steam alternative reflected state-of-the-art pollution controls including high efficiency SO_2 and particulate removal, and catalytic reduction for NOx control (Exh. AL-40, at 7, 15). The Company explained that the catalytic reduction

[137] The Company stated that the higher VOC and CO emissions for the proposed project versus the gas/oil GTCC alternative is due to the higher availability assumed for Altresco, 92 percent, as opposed to the availability rate of the gas/oil GTCC alternative at 86.6 percent (Exh. HO-RR-86).

technology for the GTCC alternatives differs from the technology for the coal units, in that the coal units are assumed to use a type of nonselective catalytic reduction ("NSCR") control technology. The Company noted that NSCR that has been established as best available control technology ("BACT") (Tr. 13, at 131-132).

The record indicates that the proposed project has the lowest estimated emissions for five of the seven pollutants, and the gas/oil GTCC alternative has the lowest emissions for two of the seven pollutants. See Table 7, above. However, although Altresco noted that its CO and VOC emission rates are higher than those of the gas/oil GTCC alternative, the tpy figures are very similar for the proposed project and the gas/oil GTCC alternative and reflect the difference in assumed availability rather than technology or fuel differences. The largest differential in emissions, comparatively, occurs in the categories of SO_2 and NOx for the CFB alternative, pulverized coal steam alternative and the residual oil steam alternative relative to the proposed project, the gas/oil GTCC alternative and the oil-fired GTCC alternative. However, the Siting Board notes that while the SO_2 output for the oil-fired GTCC alternative is substantially lower than the CFB alternative, pulverized coal steam alternative and residual oil steam alternative, it is substantially higher than that for both the proposed project and gas/oil GTCC alternatives. In addition, the oil-fired GTCC alternative has the highest PM-10 emissions of all the technologies. Finally, the CO output for the CFB alternative is approximately 500 tpy higher than the next lowest emission rate for an alternative technology.

Accordingly, the Siting Board finds that the proposed project is comparable to the gas/oil GTCC alternative with respect to air quality. Further, the Siting Board finds that the proposed project is preferable to the oil-fired GTCC alternative, CFB alternative, pulverized coal steam alternative and residual oil steam alternative with respect to air quality.

b. Fuel Transportation

(1) Description

Altresco asserted that the GE site is located in relative close proximity to an existing natural gas pipeline and that this factor clearly favors natural gas as the preferred fuel (Exh.

AL-40, at 13). The Company stated that gas would be supplied to the proposed project from the existing pipeline via a 2.5-mile pipeline proposed to be located primarily in an existing railroad ROW that has been used for public purposes for many years (see Section II.C.3.b. for a further discussion of fuel supply) (Exh. HO-PA-17; Tr. 7, at 20). The Company indicated that this route predominantly involves previously disturbed land (Tr. 7, at 20). Altresco stated that the proposed project is located close to the end of a lateral pipeline, but asserted that this location does not detract from the advantages of gas relating to other fuels because the Company has contracted for firm service with Tennessee (Exh. HO-PA-18). Altresco also stated that the Company's analysis took into account the items that would need to be upgraded specifically for the proposed project or the gas/oil GTCC alternative, and further stated that any upgrades or additional work that Tennessee may need to implement to maintain their systemwide service, would be outside the scope of this alternatives analysis (Tr. 13, at 57).

The Company assumed that both the proposed project and the gas/oil GTCC alternative would rely primarily on the same natural gas pipelines, utilizing trucks solely to transport the required oil supply (Exh. AL-40, attach. RLC-8). The record indicates that Altresco would require approximately 130 trucks per year for the five-day oil supply while the gas/oil GTCC alternative would require 1,370 trucks per year for the two-month supply (id.; Exh. HO-RR-86).

The Company stated that the alternatives that rely completely on liquid or solid fuel would transport fuel to the site via rail (Exh. AL-40, at 13). The Company added that these alternatives would require 4,000-5,000 rail cars per year, the approximate equivalent of one 100 car train per week (id.).[138] Altresco further stated that the rail transport route for either liquid or solid fuels associated with the oil-fired GTCC alternative, CFB alternative, pulverized coal steam alternative and residual oil alternative would extend through Boston

[138] The alternatives utilizing solid or liquid fuel exclusively would require the following number of rail cars per year: oil-fired GTCC alternative -- 4,110; CFB alternative -- 5,010; pulverized coal steam alternative -- 5,040; and residual oil steam alternative -- 4,085 (Exh. AL-40, attach. RLC-8).

and then travel north to the site via the Eastern Route Mainline ("mainline") (Exh. PA-20). The Company also stated that the mainline currently serves the North Shore MBTA commuter rail, at a level of 48 passenger trains per weekday, and approximately one freight train per day (id.; Exh. HO-RR-86). The Company stated that the solid or liquid fuel shipments for the proposed project or alternatives would consist of one to two trains per week, and further indicated that the level of transport could be scheduled as to not interfere with the existing use of the mainline (Exh. HO-RR-85). Therefore, Altresco indicated that existing rail facilities should be sufficient to transport the required fuel to the site (id.). Altresco categorized the land use along the mainline as including mixed industrial, commercial and residential areas, and also including coastal marsh contained within the Rumney Marsh Area of Critical Environmental Concern ("ACEC") (Exh. HO-PA-20).

The Company indicated that additional rail traffic on the mainline due to fuel delivery would add environmental impacts to the area, including increased air emissions, elevated noise levels, traffic disruptions at grade crossings, and aesthetic impacts (id.). Altresco stated that it considered the likelihood of environmental impacts due to the gas pipeline in a general sense, and acknowledged that there would be some environmental impacts (Tr. 13, at 56). However, the Company asserted that the right-of-way to be utilized for the required gas pipeline is currently used for gas pipeline and sewer line routings and, therefore, the environmental impacts would be minimized (Exh. HO-PA-17). Further, Altresco asserted that any impacts associated with the pipeline would occur during installation and would be temporary in nature, while the impacts of fuel delivery via rail transportation would occur over the life of the project (Exh. HO-PA-20).

(2) Analysis

With regard to the transportation of gas to the proposed project, the Company presented evidence that the proposed 2.5-mile pipeline would likely travel predominantly in an existing railroad ROW. The Siting Board notes that this route would minimize construction-related impacts such as vegetative alteration and tree clearing, as well as impacts on surrounding residences. However, the Company indicated that the environmental impacts of any other associated upgrades to the existing interstate system to provide the dedicated pipeline capacity for the proposed project were not addressed. Further, we note that there is potential that the route of the new pipeline may vary. In addition, delivery of back-up fuel for the proposed project, requiring up to approximately 130 truckloads annually, would result in some additional environmental impact.

With regard to the alternatives, the Siting Board notes that four alternatives, the oil-fired GTCC alternative, the CFB alternative, the pulverized coal steam alternative, and the residual oil steam alternative would rely exclusively on liquid or solid fuel. The record indicates that all four alternatives would require rail delivery of approximately 4,000 to 5,000 rail car loads of fuel annually, along the mainline -- a rail line currently used for commuter rail purposes. However, the Company stated that transport of the fuels could be scheduled without interfering with the existing use of the rail line.

With regard to the solid fuel alternatives, the record demonstrates that the fuel transportation requirements for the CFB and pulverized coal alternatives are essentially the same. In comparing the CFB and pulverized coal alternatives to the proposed project, the Siting Board notes that rail traffic could have continual impacts over the life of the project, specifically in relation to potential traffic interruptions and noise. However, such impacts have not been substantiated for the affected rail route. While the Company did identify types of impacts associated with the increased rail transportation, such as traffic interruptions, additional noise, and other environmental impacts to the surrounding area, the Siting Board notes that the Company has not presented evidence that such impacts would be of significance along the affected route, based on such factors as existing rail transport volumes, at-grade crossings, and the nature of abutting land use. Further, the ability to mitigate these impacts has not been addressed by the Company.

With respect to the oil-fired GTCC alternative and the residual oil steam alternative, the Siting Board notes that predominant reliance on liquid fuels pose greater environmental risks that other fuels in the event of accidental spillage during transport. In a previous review, the Siting Board found that the environmental impacts of accidently released oil, including seepage into the soil and groundwater, would be greater than the impacts of either coal or gas if accidentally released into the environment. EEC (Remand) at 75.

The gas/oil GTCC alternative would involve pipeline impacts essentially similar to those of the proposed project, as both technologies would utilize pipeline facilities as their primary means of fuel transportation. However, in addition to the gas pipeline impacts, the gas/oil GTCC alternative includes up to two months of oil-fired operation, requiring delivery of up to 1,370 truck loads of oil. Further, as in the case of the oil-fired GTCC and the residual oil alternatives, the environmental impacts of an accidental oil spill would be of greater concern than under the proposed project.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC alternative, oil-fired GTCC alternative, CFB alternative, pulverized coal alternative, and residual oil alternative with respect to transportation impacts.

c. Land Use and Fuel Storage

The Company stated that the proposed site is limited with regard to the size of a facility that can be constructed on it, as the land area is constrained by the existing GE River Works facilities (Exh. AL-40, at 14). As noted above, there is no additional surplus property available within the River Works complex for Altresco to acquire (Tr. 13, at 46). The Company stated that its project would impact approximately six acres of land, while the surrounding GE River Works complex would serve as a substantial buffer from abutting residences (id.; Exh. HO-PA-21). The Company provided data indicating that the gas/oil GTCC and the oil-fired GTCC alternatives would each require eight acres; the CFB alternative and pulverized coal steam alternative would each require 48 acres; and the residual oil steam alternative would require 40 acres (Exh. AL-40, attach. RLC-8).[139] The

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[139] The Company reported that the estimated site size for the generic GTCC alternatives was based on a nominal 120 MW rating, while the CFB alternative, pulverized coal steam alternative and the residual oil steam alternative site sizes were based on a (continued...)

Company indicated that all land use figures included fuel storage requirements, which were obtained from the 1991 GTF Report (id.).[140]

With respect to fuel storage for the proposed project itself, the Company stated it would utilize off-site storage of back-up oil in conjunction with the operation of a 10,000 gallon delivery truck (See Section II.C.3.b. for a further discussion of back-up fuel supply for the proposed project) (Exh. HO-PA-19). The Company indicated that it has a contracted firm supply for 365 days of gas, and therefore, would not require the amounts of back-up storage associated with the technology alternatives (id.; Exh. AL-40, attach. RLC-8).

Altresco stated that it assumed a 30-day on-site fuel storage capacity for all five of the alternatives (Exh. HO-PA-19). The Company explained that this figure is based on the design value associated with the reliance on rail and/or water transport of liquid or solid fuels (id.). Altresco indicated that the storage requirements for the GTCC gas/oil alternative, the oil-fired GTCC alternative, and the residual oil steam alternative would be 800,000 gallons of oil located on two acres (Exh. AL-40, attach. RLC-8). For the CFB alternative

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[139](...continued)
nominal 200 MW rating (Exh. AL-40, attach. RLC-8).

The Siting Board notes that utilizing one nominal MW size for all of the identified alternatives would provide different comparative results than detailed above. In addition, the Siting Board notes that the GTF report does not utilize a 120 MW nominal size but provides data in 100 MW increments. Therefore, for a nominal 100 MW size the 1992 GTF indicates that the gas/oil GTCC and the oil-fired GTCC alternative would utilize eight acres; the CFB alternative and pulverized coal steam alternative would utilize 37 acres; and the residual oil steam alternative would utilize 31 acres (Exh. HO-PA-5). In addition, for a nominal 200 MW size the 1992 GTF indicates that the gas/oil GTCC and the oil-fired GTCC alternative would utilize eleven acres; the CFB alternative and pulverized coal steam alternative would utilize 48 acres; and the residual oil steam alternative would utilize 40 acres (id.).

[140] The Siting Board notes that while the Company stated that the plant area data was taken from the 1991 GTF Report, the Company provided pertinent pages from the 1992 GTF as documentation for the performance data and site size (Exhs. AL-40, attach. RLC-8; HO-PA-5).

and pulverized coal steam alternative, the Company estimated storage requirements would be 50,000 tons of coal located on three acres (id.).

The record indicates that the proposed project would require approximately six acres and the generic alternatives, when taken on an equal nominal ranking of 200 MW, would require from eleven acres to 48 acres. Altresco has indicated that the land available within the GE River Works Complex to site a facility is limited, and that its proposal, including fuel storage would use a small parcel of available land, consisting of approximately six acres. As indicated by Altresco, it is also important to factor in the existence of an adequate buffer for any type of facility. Altresco has demonstrated that the GE River Works complex functions as an adequate buffer from the surrounding communities.

The Siting Board notes that while the gas/oil GTCC and the oil-fired GTCC alternatives would require close to twice the acreage required for the proposed project, the increment of an additional five acres may only generate a small increase in land use impacts and could conceivably still be located on the GE site. Accordingly, the Siting Council finds that the proposed project is comparable to the GTCC gas/oil alternative and oil-fired GTCC alternative in regard to land use and fuel storage impacts.

Further, the Siting Board notes that the land requirements associated with the residual oil steam alternative at 40 acres and the CFB alternative and pulverized coal steam alternative at 48 acres are substantially larger than the aforementioned alternatives. It would be extremely difficult to site facilities of this size on the existing GE site or in the general vicinity. Accordingly, the Siting Board finds that the proposed project is preferable to the CFB alternative, pulverized coal steam alternative, and residual oil steam alternative facilities in regard to land use and fuel storage impacts.

d. Water Use

Under the category of water use the Company has included three sub-categories: water usage associated specifically with cooling makeup; water usage associated with any other forms of makeup; and wastewater discharges, of which water for cooling makeup constitutes the most significant contribution by volume (Exhs. AL-40, attach. RLC-9; HO-RR-86). The

Company provided data indicating that for total makeup purposes the water usage would be on the order of 1,224 million gallons per day ("mgpd") for the proposed project; 1,250 mgpd for the gas/oil GTCC alternative; 1,380 mgpd for the oil-fired GTCC alternative; and 2,690 mgpd for the remaining alternatives, including the CFB alternative, the pulverized coal steam alternative and the residual oil steam alternative (id.).[141] With respect to wastewater, the proposed project would discharge 290 mgpd; the gas/oil GTCC alternative, the pulverized coal steam alternative and the residual oil steam alternative would each discharge 300 mgpd; the oil-fired GTCC alternative would discharge 370 mgpd; and the CFB alternative would discharge 500 mgpd (id.).

The Company stated that based on the above data, water requirements of the proposed project would be very similar to that of the gas/oil GTCC alternative, and that the slightly higher requirements of the generic gas/oil GTCC alternative would be attributable to the need for water injection for NOx control during the two months of oil firing (Exh. AL-40, at 16). The higher quantity of water usage for the oil-fired GTCC alternative is also attributable to the need for water injection during NOx control associated with oil use (id.). Further, the Company reported that the significantly higher water use for the CFB alternative, pulverized coal steam alternative and residual oil steam alternative facilities is attributable to the full steam cycle options inherent in these systems, versus combined-cycle with the use of dry low-NOx, inherent in these systems (id.).

The record indicates that the water usage requirements are very similar for the proposed project, the gas/oil GTCC alternative and the oil-fired GTCC alternative. The full steam cycle design associated with the CFB alternative, pulverized coal steam alternative and residual oil steam alternative would lead to an approximately 100 percent increase in water usage requirements over the GTCC alternatives. Accordingly, for the purpose of this review, the Siting Board finds that the proposed project is comparable to the gas/oil GTCC and oil-fired GTCC alternative facilities with respect to water use. Further, the Siting Board

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141 The Company assumed that the proposed project, gas/oil GTCC alternative and oil-fired GTCC alternative would each incorporate dry low-NOx controls, thereby reducing water requirements associated with pollution controls (Exh. HO-PA-10).

finds that the proposed project is preferable to the CFB alternative, pulverized coal steam alternative and residual oil steam alternative with respect to water use.

e. Solid Waste

The Company provided data that indicated that all of the GTCC alternatives -- the proposed project, the gas/oil GTCC alternative and the residual oil GTCC alternative -- would produce the same quantity of solid waste, consisting of 700 tpy (Exh. AL-40, attach. RLC-9). Altresco identified the solid waste as sludge created by the pretreatment of recycled secondary sewage effluent that is to be used as cooling tower makeup (See Section III.C.2.b. for a further discussion of the use of effluent) (id. at 16; Exh. HO-E-1, at 5-15). Altresco noted that the estimated quantity of sludge to be produced by the generic GTCC alternatives is based on the assumption that the other generic alternatives would also utilize secondary effluent (Exh. AL-40, at 17).

The Company's data indicates that the residual oil steam alternative would generate 35,000 tpy, the second highest quantity of solid waste (id., attach. RLC-9). Further, the Company presented data indicating that both the CFB alternative and pulverized coal steam alternative facilities would generate 145,000 tpy of solid waste (id.). Altresco stated that the solid waste for all three alternatives would consist primarily of the by-products from the removal of SO_2 from combustion exhaust (id. at 17). The Company further explained that the higher quantity of solid waste associated with the two facilities fueled by coal reflects the additional requirements for the removal of coal ash from the boiler and particulate systems (id.). Altresco stated that, although the potential for beneficial reuse of coal ash exists, the coal ash produced from the operation of the coal-fired facilities would still need to be transported from the site resulting in impacts (Exh. HO-PA-24).

Noting that the form of transportation for solid waste removal depends on the quantity to be disposed, the Company indicated that the proposed project, the gas/oil GTCC alternative and the oil-fired GTCC alternative would use truck transport and the CFB alternative, pulverized coal steam alternative and residual oil steam alternative would use rail transport (Exh. AL-40, at 17, attach. RLC-9).[142] Altresco stated that 20 trucks per year would be necessary for each of the GTCC options while 350 rail cars per year would be necessary for the residual oil steam alternative, and 1,450 rail cars would be utilized for both the CFB alternative and pulverized coal steam alternatives (id.).

The record indicates that the amount of solid waste produced by the proposed project, the gas/oil GTCC alternative, and the oil-fired GTCC alternative would be significantly less than the quantities produced by the CFB alternative, pulverized coal steam alternative and residual oil steam alternative. The amount produced by the GTCC alternatives, 700 tpy, is approximately .5 percent of the amount produced by the CFB alternative and pulverized coal facilities, and 2 percent of the amount produced by the residual coal steam alternative. Further, the large quantities of solid waste produced by the CFB alternative, pulverized coal steam alternative and residual oil steam alternative would necessitate numerous rail trips to dispose of the waste off-site. The Siting Board notes that in most cases coal ash is shipped out on the return trip via the train that transported the coal to the site. However, the record does not provide details concerning such overlap and its effect on rail transport requirements. In addition, the record indicates that coal ash potentially could be put to productive use, reducing disposal requirements. However, such reuse is speculative, and the amount of solid waste to be transported off-site would remain the same in any case.

Accordingly, the Siting Board finds that the proposed project is comparable to the gas/oil GTCC alternative and the oil-fired GTCC alternative with respect to solid waste impacts. In addition, the Siting Board finds that the proposed project is preferable to the

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142 The Siting Board notes that although the Company did not specifically indicate where the solid waste from the gas/oil GTCC alternative and the oil-fired GTCC alternative would be disposed, the Siting Board notes that the Company stated that the solid waste from the proposed project, comprising the same type of waste as the two generic alternatives, would be trucked off-site and disposed in a licensed commercial landfill (Exh. HO-E-1, at 5-19). In addition, Altresco stated that the solid waste removed from the CFB alternative, pulverized coal steam alternative, and the residual oil steam alternative, would be disposed at a remote location (Exh. AL-40, at 17).

CFB alternative, pulverized coal steam alternative and residual oil steam alternative with respect to solid waste impacts.

f. Findings and Conclusions on Environmental Impacts

With respect to air quality impacts, the Siting Board has found that (1) the proposed project would be comparable to the gas/oil GTCC alternative, and (2) the proposed project would be preferable to the oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to fuel transportation impacts, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, the oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to land use impacts, the Siting Board has found that (1) the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives, and (2) the proposed project would be preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to water use impacts, the Siting Board has found that (1) the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives, and (2) the proposed project would be preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to solid waste impacts, the Siting Board has found that (1) the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives, and (2) the proposed project would be preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

In comparing the overall environmental impacts of the proposed project and the gas/oil GTCC alternative, the Siting Board has found that the proposed project would be comparable to the gas/oil GTCC with respect to air quality, land use, water use, and solid waste and preferable with respect to fuel transportation.

Accordingly, based on the foregoing, the Siting Board has found that the proposed project is comparable to the gas/oil GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the oil-fired GTCC alternative, the Siting Board has found that the proposed project would be preferable to the oil-fired GTCC with respect to air quality and fuel transportation and comparable with respect to land use, water, and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board has found that the proposed project would be preferable to the oil-fired GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the CFB alternative, the Siting Board has found that the proposed project would be preferable to the CFB alternative with respect to air quality, fuel transportation, land use, water use, and solid waste.

Accordingly, based on the foregoing, the Siting Board has found that the proposed project would be preferable to the CFB alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the pulverized coal steam alternative, the Siting Board has found that the proposed project would be preferable to the pulverized coal steam alternative with respect to air quality, fuel transportation, land use, water use, and solid waste.

Accordingly, based on the foregoing, the Siting Board has found that the proposed project would be preferable to the pulverized coal steam alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the residual oil steam alternative, the Siting Board has found that the proposed project would be preferable to the residual oil steam alternative with respect to air quality, fuel transport, land use, water use, and solid waste.

Accordingly, based on the foregoing, the Siting Board has found that the proposed project would be preferable to the residual oil steam alternative with respect to environmental impacts.

Accordingly, in comparing the overall environmental impacts of the proposed project, the Siting Board finds that the proposed project and the gas/oil GTCC alternative, would be preferable to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to environmental impacts.

4. Cost

The Siting Board evaluates the proposed project in terms of whether it minimizes cost by determining (1) if the proposed project is superior to a reasonable range of practical alternatives in terms of cost, and (2) if the proposed project offers power at a cost below purchasing utilities' avoided costs.

a. Project Cost Comparison

(1) Description

The Company compared the costs of the proposed project with the gas/oil GTCC alternative, oil-fired GTCC alternative, CFB alternative, pulverized coal steam alternative, and residual oil steam alternative (Exh. AL-40). Altresco explained that it modelled the projected total revenue requirements[143] of each of the alternatives over a 20-year period, with an assumed in-service date of January 1, 1996 (id. at 4, 5).[144]

The Company stated that it relied on the 1992 GTF for the cost and performance data for the generic facilities, which included: capital costs and escalators; O&M costs and

143 To develop a cost in dollars per megawatt hours ("$/MWH") for each option, the Company discounted the annual revenue requirements into net present value terms and developed 20-year levelized costs (Exh. AL-40, at 5).

144 In projecting total revenue requirements for each alternative, Altresco utilized consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. AL-40, at 4, 5).

escalators; fuel costs and escalators;[145] availability; and heat rates (id., Exhs. HO-PA-5; AL-40, attach. RLC-2 and attach. RLC-6).[146] Altresco also provided (1) high and low fuel price scenarios, based on assuming annual escalation factors ten percent higher and ten percent lower than those in the 1992 GTF, for each of the generic facilities[147], and (2) high and low interest rate scenarios, based on applying a nine percent and 13 percent interest rate to all units, versus the base assumption of an 11 percent interest rate (Exh. AL-40, at 8). The Company asserted that its analyses demonstrate that the proposed project is superior to the identified generic options with respect to cost under a variety of alternative future scenarios (id. at 9; Company Supplemental Brief at 22).

Altresco indicated that in order to provide cost estimates for the alternative technologies consistent with the cost estimate for the proposed project, the Company adjusted some of the base assumptions contained in the 1992 GTF, specifically those items relating to fuel prices, heat rate and additional capital costs (Exh. AL-40, at 6, 7). In regard to fuel prices, the Company updated the assumed prices to reflect the year-to-date fuel price for the New England region (id.). Specifically, the coal, distillate oil, and residual oil figures are average New England prices quoted from Electric Power Monthly, published by the DOE, for the period January through May 1992 (Exh. HO-PA-7). Altresco stated that it derived natural gas price estimates for both spot and interruptible gas through its parent companies' experience with tracking natural gas prices, and including spot and interruptible transportation prices through the beginning of October, 1992 (id.). Further, the Company provided a comparison of its gas prices with DOE prices for the period of January through

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145 The Company noted that the fuel price escalators for the coal and residual oil units were escalated at rates specified in the 1992 GTF through the first year of operation and thereafter were escalated at 4 percent above the GNP deflator, as directed in the report (Exhs. HO-PA-5; HO-PA-6).

146 The Company utilized project specific cost data for the proposed facility based on the actual capital cost information contained in the construction, O&M and fuel contracts (Tr. 13, at 102, 115, 116, 129).

147 Altresco did not analyze high and low fuel price scenarios on the proposed project, as the proposed projects' fuel contract contains a fixed escalator (Exh. AL-40, at 8).

April 1992, which detailed that the DOE average price of interruptible gas delivered to power plants, at \$2.57/MMBtu was slightly higher than the initial price Altresco used in its cost analysis, at \$2.53/MMBtu (id.).

With regard to the heat rate presented in the 1992 GTF, the Company adjusted this rate to reflect the fact that the generic alternatives are cogeneration facilities and the GTF assumes stand-alone facilities (Exh. AL-40, at 7).[148] Altresco explained that this adjustment accounts for the energy input required to provide 55,000 lbs/hr of steam to the GE plant on an annual, average basis (Exh. HO-PA-10).

With regard to adjusting capital costs presented in the 1992 GTF, the Company added the cost of SCR equipment for the two generic combined-cycle units -- the gas/oil GTCC alternative and the oil-fired GTCC alternative, however it did not include an adder for the cost of dry low-NOx combustion technology (Exhs. HO-PA-11; AL-40, at 7).[149] In addition, the cost of an on-site natural gas pipeline lateral, and associated compression was added to the gas/oil GTCC alternative (Exh. AL-40, at 7). Finally, transmission line costs were added to each generic option (id.). Table 8, below, details the costs for the alternatives.

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148 In addition to adjusting the heat rate to reflect cogeneration capability, the Company also adjusted the heat rate on the generic combined cycle facilities by 0.5% to take into account the energy penalty of incorporating SCR for NO_x control (Exh. HO-PA-10).

149 The Company stated that it did not make any additional adjustments to reflect the costs of other emission control equipment (Exh. HO-PA-11). Altresco stated that it understood that the 1992 GTF included the cost of scrubbers in the capital cost estimates for the coal-fueled alternatives (id.).

TABLE 8

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS
(1996$/MWH)

	Altresco	Gas/Oil GTCC	Oil Fired GTCC	CFB	Coal Steam	Oil Steam
Levelized Cost (1996$/MWH) [150]	$74.31	$93.63	$121.41	$119.76	$127.89	$106.16
Heat Rate (Btu/kWh)	8600	8904	8904	10077	10402	9712
Availability Factor	92.0%	86.8%	86.8%	83.5%	81.4%	84.7%
Capital Costs 1996$/KW-yr	$1,069	$1,064	$1,034	$2,977	$3,122	$1,834

Source: Exh. AL-40, attach. RLC-2 (rev.)

Altresco asserted that its estimates of costs for the generic alternatives were conservative, that it tended to understate the cost based on a number of factors, each attributable to one or more specific generic alternative (Exhs. HO-PA-3; HO-PA-8; HO-PA-11). For example, the Company stated that the cost estimate for the gas/oil GTCC alternative was conservative because: (1) it was assumed that the alternative could be

150 As noted, the levelized cost estimates are based on data from the 1992 GTF. The Siting Board notes that another reference source has also been used in prior cases, the Electric Power Research Institute Technical Assessment Guide ("TAG Report"). The Company stated that utilizing the TAG Report results in some differences from the 1992 GTF in the ranking of levelized costs for generic technologies, specifically that the levelized costs of the coal units would be cheaper than those of the oil-fired GTCC alternative and residual oil steam alternative (Tr. 13, at 40-41, 133). However, Altresco stated that the proposed project and the gas/oil GTCC would still show the lowest and second-lowest levelized costs, respectively, both outranking the coal alternatives (id., at 40).

operated with ten months of interruptible gas rather than firm gas, and two months of backup oil;[151] (2) local distribution company charges were not included, but likely would be applicable to a generic gas/oil GTCC alternative; and (3) the initial price utilized for spot gas was low relative to current prices[152] (Exhs. HO-PA-3; HO-PA-8). Further, the Company noted that the price of distillate oil was based on a content of 0.3 percent sulfur, not reflecting the estimated seven to ten cents per gallon higher cost for the 0.05 percent low-sulfur fuel to be used, thereby understating the likely cost of the gas/oil GTCC alternative, the oil-fired GTCC alternative and the residual oil steam alternative (Exh. HO-PA-3). In addition, the Company stated that it did not add the cost of dry low-NOx combustion technology to the gas/oil GTCC and oil-fired GTCC alternatives, even though such technology is to be included in the proposed project and was assumed for the environmental analysis of the alternatives (Exh. HO-PA-11). Finally, Altresco noted that it did not include the cost of treating secondary untreated effluent from the LWSC, which would affect the cost of all of the generic alternatives (id.).

Altresco asserted that the lower costs for its proposed project (see Table 8) are attributable to the extremely favorable firm price gas contract, which combines both a low base price with a fixed average escalation rate that is lower than that under every present New England gas price forecast (Tr. 13, at 97). The Company stated that even if there were a substantial savings in the cost of interruptible gas relative to the cost of firm gas, firm gas would still be preferable in the long-run as there is uncertainty regarding future price escalation (id. at 95). In addition, for all of the technologies, the Company has stated that it

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151 Altresco reported that it would be extremely difficult to operate a project on ten months of interruptible gas, as eight to nine months per year has traditionally been the extent of the period for available interruptible gas supply in New England (Exh. HO-PA-3; Tr. 13, at 93).

152 The Company indicated that as of October 1992, the price of spot gas had risen over the most recent three months, whereby the cost was 36 percent higher than Altresco's assumed 1992 price for the generic facility (Exh. HO-PA-7). The Company noted that the delivered price of interruptible gas was also higher than their projected price (id.).

assumed fuel prices will rise in the future, and that there is no basis for anticipating level or declining gas prices over 20 years (id. at 96).

Finally, the Company provided analyses of the project costs of its proposed project relative to the avoided costs of seven Massachusetts utilities (Exhs. AL-31 through AL-39 inclusive). These analyses indicated that Altresco would be able to offer its power at or below all of the utilities' avoided costs (id.).

(2) Analysis

With respect to the proposed project, the record indicates that the 20-year levelized cost would be $74.31/MWH. In comparing the proposed project to the alternatives, the Company's estimates of the 20-year levelized costs of the alternatives and the respective percentage difference from the 20-year levelized cost of the proposed project are as follows: (1) the gas/oil GTCC alternative, $93.63/MWH, 20.6 percent higher than that of the proposed project; (2) the oil-fired GTCC alternative, $121.41/MWH, 38.8 percent higher than that of the proposed project; (3) the CFB alternative, $119.76/MWH, 37.9 percent higher than that of the proposed Project; (4) the pulverized coal steam alternative, $127.89/MWH, 41.9 percent higher than that of the proposed project; and (5) the oil steam, $106.16/MWH, 30.0 percent higher than that of the proposed project.

The Siting Board notes that the Company's cost analysis was based on 20-year levelized cost, and did not include cost estimates over a longer 25-year or 30-year life that may be more favorable for considering the cost-effectiveness of the most capital-intensive technologies, notably the CFB and pulverized coal steam alternatives. Given that the costs of a generating facility are likely to be spread over a 30-year or longer period rather than a 20-year period, and that the capital costs of the CFB alternative or pulverized coal steam alternative are significantly higher than the proposed project, the Siting Board recognizes that the use of a 30-year levelized cost could decrease the cost of CFB and pulverized coal steam alternatives relative to the proposed project . See, EEC (Remand) at 144. However, given the significant difference in the 20-year levelized costs of the proposed project versus the CFB alternative and pulverized coal steam alternative, it is highly unlikely that the outcome would reflect a large enough change in levelized costs over 30-years for the proposed project relative to those of the CFB and pulverized coal steam alternatives to alter the relative cost superiority of the proposed project.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to cost.

In addition, the record indicated that Altresco could provide power at a cost below seven Massachusetts utilities' avoided costs. Accordingly, the Siting Board finds that the proposed project is likely to offer power at a cost below the purchasing utilities' avoided cost.

5. Reliability

In this section the Siting Board compares the proposed project to the technology alternatives with respect to unit-specific reliability. The Siting Board notes that unit-specific reliability relates to the predictability of unit operation. As such, the Siting Board considers such factors as the anticipated availability, the maturity of the technology, and the reliability of the fuel supply in comparing the reliability of the proposed project with the reliability of the technology alternatives. EEC (Remand) at 149.

Altresco stated that it based its reliability assumptions on fuel supply, transportation arrangements, and project availability (Exh. AL-42, at 9). The Company acknowledged that since all of the alternatives have an expected availability of over 80 percent, all are considered highly reliable technologies, however, the Company did note that the proposed project's availability is more than five percent higher than the other alternatives (id.). With respect to the gas/oil GTCC alternative, the oil-fired GTCC alternative, and the residual oil steam alternative, the Company noted reliability problems associated with dependence on imported oil, such as supply disruptions and price spikes (id., at 10).[153] In fact, in terms

153 The Company noted imported oil comprises approximately 50 percent of U.S. oil supplies (Exh. AL-42, at 10).

of supply and deliverability, Altresco noted that both gas and coal are domestic resources for which a firm supply and transportation arrangements are available (Exh. HO-PA-16). Therefore, the Company asserted that, based on fuel supply and transportation reliability, the proposed project is superior to the gas/oil GTCC, the oil-fired GTCC, and the residual oil alternatives, and comparable to the CFB and pulverized coal alternatives (id.).

With respect to the proposed project, the Company indicated that the availability of the proposed project would be 92 percent (id.). As discussed in Section II.B.2., above, the Company based this rate on the actual availability rate of the Altresco Pittsfield facility which is technologically similar to the proposed project. In addition, the Company has contracted for a firm, long-term fuel supply and transportation arrangement, ensuring that the gas supply for the proposed project would be limited in its volatility. See Section II.C.3.b., below.

In comparing the reliability of the proposed project to the reliability of the gas/oil GTCC alternative, the Siting Board notes that the availability factor for the gas/oil GTCC alternative is assumed to be 86.8 percent, 5.6 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the gas/oil GTCC alternative in annual facility operation does not represent a significant difference for purposes of this review in and of itself. However, the Siting Board notes that the gas/oil GTCC alternative does not have a realistic fuel supply and likely would not be financiable or permittable based on the assumed fuel supply (see Section II.B.4.b, above).[154] Therefore, taken together, both the lower availability and unrealistic fuel supply renders the oil/gas GTCC alternative a potentially unreliable energy source. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability.

154 Altresco noted that interruptible gas is subject to regular curtailment, primarily during cold weather periods (Exh. AL-42, at 10). Further, the Company stated that the price of spot gas is volatile, with no end to future volatility predicted (id.).

In comparing the proposed project to the oil-fired GTCC alternative, the Siting Board notes that the record indicates that the availability factor of the oil-fired GTCC alternative would be comparable to the gas/oil GTCC alternative. As the Siting Board finds no basis in the record to support the Company's argument that dependence on imported oil presents reliability problems, the Siting Board must reject such a conclusion. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the oil-fired GTCC alternative with respect to reliability.

With regard to the CFB alternative, the record indicates the likely availability factor would be 83.5 percent, 9.2 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the CFB alternative in annual facility operation, but does not represent a significant reliability difference for purposes of this review. Further, as the Company noted, coal, a domestic fuel source does not raise reliability concerns. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the CFB alternative would be comparable with respect to reliability.

With regard to the pulverized coal alternative, the record indicates the likely availability factor would be 81.4 percent, 11.5 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the pulverized coal in annual facility operation, but does not represent a significant difference for purposes of this review. Further, as noted above, the fuel supply and transportation arrangements would be comparable to the CFB alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the pulverized coal alternative would be comparable with respect to reliability.

With regard to the residual oil alternative, the record indicates the likely availability factor would be 84.7 percent, 8 percent lower than the availability of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the residual alternative in annual facility operation, but does not represent a significant difference for purposes of this review. In addition, as noted above, the fuel supply and transportation arrangements is comparable to the oil-fired GTCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the residual oil alternative with respect to reliability.

Accordingly, the Siting Board finds that the proposed project would be comparable to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to reliability. Further, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

In City of New Bedford, the Court stated that "the statute mandates that the [Siting C]ouncil balance environmental harm that would be caused by a new power plant against the other statutory objectives -- providing a necessary energy supply at the lowest possible cost." 413 Mass. at 485. In addition, the Court stated "[t]he statutory mandate, however, requires that the energy the facility will supply is necessary for the Commonwealth; that the supply of the energy involves a minimum impact on the environment; and that such energy is supplied at the lowest possible cost. Thus, the statutory balance involves weighing minimum environmental impact and cost." Id., 413 Mass. at 486. In addition, the Court stated that the Siting Council would need to explicitly state that it was approving a project with greater environmental impacts than alternatives on the basis of a determination that other factors outweighed those environmental impacts. Id. at 490.

In Section II.B.1., above, the Siting Board found that, in order to establish that a proposed project is preferable to technology alternatives in its ability to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board would require the applicant to establish 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.

In Sections II.B.3., II.B.4., and II.B.5., above, the Siting Board has analyzed the record, by comparing the proposed project against generating technology alternatives that have been determined capable of meeting the identified need, and on the basis of their specific impacts on the environment, costs and reliability.

In comparing the environmental impacts of the proposed project to the environmental impacts of the technology alternatives, the Siting Board has found that the proposed project and the gas/oil GTCC alternative would be preferable to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to environmental impacts.

In comparing the costs of the proposed project to the costs of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to cost.

In comparing the reliability of the proposed project to the reliability of the technology alternatives, the Siting Board has found that (1) the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability, and (2) the proposed project would be comparable with respect to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to reliability.

As noted above, the proposed project is preferable to the gas-oil GTCC alternative with respect to cost and reliability. Further, the proposed project is comparable to the gas-oil GTCC with respect to environmental impacts. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the gas-oil GTCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the oil-fired alternative, as noted above, the proposed project is preferable to the oil-fired GTCC alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the oil-fired GTCC alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the oil-fired GTCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the CFB alternative, as noted above, the proposed project is preferable to the CFB alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the CFB alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the CFB alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the pulverized coal steam alternative, as noted above, the proposed project is preferable to the pulverized coal steam alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the pulverized coal steam alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the pulverized coal steam alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the residual oil steam alternative, as noted above, the proposed project is preferable to the residual oil steam alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the residual oil steam alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the residual oil steam alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

Accordingly, based on the foregoing, the Siting Board finds that the Company has established that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

C. Project Viability

1. Standard of Review

The Siting Council previously 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. Enron, 23 DOMSC at 89; EEC, 22 DOMSC at 295; 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 the 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. Enron, 23 DOMSC at 89; EEC, 22 DOMSC at 296; Altresco-Pittsfield, 17 DOMSC at 378.

Here, Altresco submits that the project fully meets each of the project viability tests, and that the proposed project will be a viable source of energy (Company Initial Brief at 81).

2. Financiability and Construction

a. Financiability

In considering a proponents' strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project would actually go into service as planned. Here, Altresco indicated that Altresco Financial the parent company of Altresco, is responsible for arranging and overseeing the financing for the proposed project (Exh. AL-2, at 8-1). The Company asserted that favorable financial scenarios, a comprehensive financing strategy, low avoided costs, and attractive financing characteristics demonstrate that the proposed project is financiable (Company Initial Brief at 81-87).

Altresco asserted that the it has financial strength and substantial experience in energy project financing (id. at 82; Exh. HO-V-21).[155] The Company stated that Altresco Financial has handled the financing for two projects in Massachusetts, the Altresco Pittsfield cogeneration facility and the Berkshire Gas Pipeline project (Exh. HO-V-21). The Company indicated that Altresco Financial is involved in the early stages of developing projects in Arizona and Nevada, but stated that it has not financed a project outside of Massachusetts (Exh. HO-B-6; Tr. 4, at 27). The Company asserted that the assets of Altresco Financial are substantial, and were documented as $190 million in its last audited financial statement (Tr. 4, at 24; Company Initial Brief at 85).[156]

Altresco stated that General Electric Capital Corporation ("GECC") would provide the construction loan financing for the proposed project (Exh. AL-2, at 8-1; Tr. 4, at 12). In addition, the Company stated that GECC has an option to provide permanent funding and would be the likely source of such funding (Exh. AL-2, at 10-1). Altresco indicated that GECC was the only choice for providing financing for the project at this time due to a prior commitment by Altresco Financial, Inc. with GECC (Exhs. HO-V-20; HO-V-27; Tr. 4, at 18). The Company explained that, as part of the terms of financing for Altresco Pittsfield, GECC has the right of first refusal to provide financing to the Altresco Lynn project and an additional project to be named later (Exh. HO-V-20; Tr. 4, at 21).[157]

155 The Company provided background data indicating that the Chairman of the Board of Altresco Financial, Inc. has 25 years of experience in project and real estate development, and the President and Chief Executive of Altresco has over 30 years of experience in financial planning and business strategies (Exh. HO-B-3).

156 Altresco indicated that this figure, in accordance with financial reporting standards, includes the Altresco Pittsfield facility even though it is a leased facility (Tr. 4, at 24).

157 The Company stated that the concessions for future financing arrangements with GECC were made after GECC agreed to finance Altresco Pittsfield on short notice following the withdrawal of Altresco's primary lender's financing commitment (Tr. 4, at 11).

Altresco stated that the project is to be financed under a sale-and-leaseback agreement (Tr. 4, at 7; Company Initial Brief at 85).[158] Mr. Lutz stated that the Altresco Pittsfield project was also financed under a sale-and-leaseback arrangement, and that this method is preferred by GECC (Tr. 4, at 11, 14). Mr. Lutz asserted that the economic returns to Altresco under a sale-and-leaseback are comparable to those under conventional mortgage financing, and further, that GECC is committed to providing market rate financing (id. at 11, 17). The Company indicated that the financing documents are in place,[159] and that it anticipated that the construction loan closing would occur at the end of 1992[160] (id. at 19; Exh. HO-V-22).

Altresco indicated that the internal rate of return ("IRR") is the accepted indicator of financial feasibility to be used for a sale-and-leaseback arrangement, as sale-and-leaseback is comparable to the utilization of 100% equity (Exh. HO-V-18; Tr. 4, at 10).[161] The Company stated that an acceptable IRR for the proposed project, given current market conditions, is in the 12% range (Exh. HO-V-18; Tr. 4, at 13). Further, Mr. Lutz asserted

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158 Under the sale-and-leaseback transaction, at the close-out of construction, prior to commercial operation, a partnership consisting of Altresco as the general partner, and GECC (or an affiliate) as a limited partner, would acquire the facility from Altresco and lease it back to Altresco (Tr. 4, at 7-8). The Company indicated that the limited partner(s) would provide the bulk of the equity (id. at 27).

159 Altresco stated that the Amended and Restated Loan and Security Agreement has been signed (Tr. 4, at 69).

160 Altresco stated that it based the December closing date on the assumption that all major permits would be issued by December 1, 1992 (Exh. HO-V-22). Mr. Lutz also indicated that if Altresco did not sell a significant amount of power by the aforementioned closing date, that the financial closing would be delayed, and that the project would have a 1996 start date rather than the 1995 start date originally envisioned (Tr. 4, at 29). However, he asserted that the project would still be viable with a 1996 on-line date (id.).

161 The Siting Board notes that in previous decisions, debt coverage ratios have been identified as the indicators used by lenders to determine financial feasibility.

that an IRR of 12% or greater indicates sufficient cash flows to provide equity holders with an acceptable rate of return (Tr. 4, at 10).

The Company provided pro formas under scenarios involving a range of capital costs and different proportions of capacity sold under long-term contracts (Exhs. HO-V-17; HO-V-31).[162] Altresco asserted that even under conservative financial assumptions, the pro formas show an acceptable IRR for the project (Company Initial Brief at 85). The Company acknowledged that under its low case scenario for long-term capacity power sales, the IRR would not meet the 12% threshold (id.).[163] However, Altresco asserted that, since it has a signed and approved contract with ComElectric for 25 MW and is the sole project in BECo's RFP 3 Award Group for 132 MW, the low case scenario for capacity sold no longer applies (see Section II.A.2., for a further discussion of power sales) (id. at 85; Exhs. HO-MB-1; HO-MB-12S; HO-RR-30). Mr. Lutz also indicated that any additional funds required over the current project-cost estimates would be handled by the sale-and-leaseback equity participants (Tr. 4, at 16). Further, he stated that if the project is delayed and interest rates rise considerably, the project would still be able to maintain an acceptable IRR to investors, as shown in the high case capital cost scenario (Exh. HO-V-31; Tr. 4, at 24).

The Company asserted that it has a comprehensive marketing strategy, centered around a marketing committee consisting of various experts in the field (Exh. AL-2, at 5-2). Altresco stated it has submitted three bids to the Massachusetts Bay Transportation Authority ("MBTA"), a bid to the Vermont Department of Public Service, and to two other utilities for smaller amounts of power (Exh. HO-MB-3). The Company further stated that it is reviewing its options to submit bids as needed, for other utility solicitations until the entire capacity of

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162 Altresco provided two alternative levels of capacity sold -- the low case assumed 85 MW sold under long-term contracts and 85 MW sold on an energy only basis, and the second case assumed 140 MW sold under long-term contracts and 30 MW sold on an energy only basis (Exh. HO-V-17).

163 The Company's analysis included a base case pro forma, assuming that 100% of the Altresco capacity will be sold under long-term contract, and two pro formas reflecting lower levels of capacity sold under long-term contracts, specifically 140 MW (83%) and 85 MW (50%) (Exh. HO-V-17).

the proposed project is committed (id.). The Company provided analyses of the project costs of its proposed facility relative to the avoided costs of several Massachusetts utilities (Exhs. AL-31 through AL-39 inclusive). These analyses indicated that Altresco would be able to offer its power at or below the utilities' avoided costs (id.). See Section II.B.4., above.

The Siting Board notes that if the Company signs a contract with BECo for 132 MW, Altresco will be in a very favorable position to obtain project financing. In addition, due to prior agreements with GECC, and GECC's direct involvement in the sale-and-leaseback arrangement, there is a strong incentive for GECC to maintain the financing relationship. In addition, Altresco pro formas indicate that Altresco would be able to offer power at or below utilities' avoided cost -- a necessity in signing additional long-term PPAs. The Company has also indicated that the sale-and-leaseback equity participants are willing to be flexible in their equity contributions. The Siting Board notes that while the financial experience of Altresco itself, is not as extensive as that of applicants in recent Siting Board decisions, the experience of the principals is strong.

Altresco has presented a number of scenarios which address the sensitivity of project finances to capital costs and the amount of capacity sold under long-term contracts. The range of assumptions provided by Altresco, including the base case assumptions, is reasonable and consistent with scenarios reviewed by the Siting Council in prior decisions. The results of these analyses indicate that in accordance with acceptable IRRs, the Altresco project is financiable under a broad array of scenarios, with the exception of one low case scenario for capacity sold under long-term contract. While the Company has determined that this scenario is no longer applicable due to its contract with BECo, the Siting Board notes that, in the event that Altresco and BECO do not sign a contract, Altresco would need to market a significant portion of its remaining capacity to be financiable. In Section II.A.5., above, the Siting Board was unable to find need for the proposed project prior to the year 2000. Therefore the Siting Board required Altresco to submit signed and approved PPAs with BECo for 132 MW or signed and approved PPAs for at least 75 percent of the proposed projects' electric output to establish need. The Siting Board notes that in light of the uncertainty of need in the early years of planned facility operation, it may be difficult for the Company to market a sufficient portion of its capacity to be financiable. Nevertheless, if Altresco complies with the condition regarding PPAs, the Company will be able to ensure that the proposed project is financiable.

Based on the foregoing, the Siting Board finds that upon compliance with the condition in Section II.A.5, above, Altresco will have established that its proposed project is financiable.

b. Construction

In considering a proponent's construction strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Here, Altresco indicated that the engineering, procurement and construction ("EPC") contract has been awarded to United Engineers and Constructors ("UE&C") (Exh. AL-4, at 2). The Company provided an executed contract between Altresco and UE&C dated January 28, 1992, to provide EPC services for the proposed project (Exh. HO-RR-20).

Altresco stated that UE&C would be responsible for the complete design, engineering, procurement, construction, installation and performance testing of the proposed facility (id.). The final contract contains a set of binding terms and conditions and a fixed price with bonus/penalty provisions (id.). Altresco stated that these conditions would ensure timeliness of completion, maximum output and efficient construction of the project (Exh. AL-2, p. 6-2). The Company indicated that it intends to utilize pre-packaged construction techniques (Tr. 3, at 72). Altresco asserted that pre-packaged construction is necessary due to the lack of available laydown area, and further noted that pre-packaged construction improves quality control (id.; Exh. HO-V-4).

Altresco stated it selected UE&C based on experience and a strong management team (Exh. HO-V-3). Further, the Company asserted that a team consisting of Mr. Gotlieb, Altresco's Vice President of Project Development, and UE&C helped pioneer the modern day concept of pre-packaging, pre-assembly, sub-assembly, and full modularization for power generating facilities (Exh. HO-V-2). Altresco also asserted that UE&C has substantial experience in the successful construction of gas turbine projects, and provided a listing and related project information including eight cogeneration and independent power projects, 13 gas turbine generation projects and 13 EPC contracts with utility companies (Exh. HO-RR-39).

In regard to the facility site and access arrangements, Altresco provided a copy of a signed 20-year site-lease agreement, containing a renewal option for an additional 20 years (Exh. AL-11, at 31). This agreement, which became effective on January 1, 1990, includes provisions for leasing a portion of GE Building 64, located on site, certain improved areas adjacent to GE Building 64, and for easement rights (id.).

Altresco further stated that it has signed an interconnection agreement for 240 MW of capacity with New England Power Service Company ("NEPCo") (Exh. HO-V-6). Mr. Gotlieb indicated that the contract was signed on February 15, 1991, and a $67,200 reservation fee has been paid (Tr. 3, at 22). Mr. Gotlieb asserted that obtaining this signed agreement contributes to the competitiveness of the proposed project, as the facility can be interconnected to the NEPCo system without any system upgrades (id. at 26).

Finally, the Company provided to the Siting Board a letter of intent between Altresco and the LWSC to provide secondary treated effluent and potable water under a long-term contract (Exh. AL-18). Altresco indicated that a final agreement was anticipated prior to July 1, 1992, however, no agreement has yet been signed (Exh. HO-E-17).

In the past, the Siting Council 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 would be able to perform as expected. Enron, 23 DOMSC at 103; Altresco-Pittsfield, 17 DOMSC at 380. Here, Altresco has submitted a signed EP&C contract. The contract includes a number of advantageous provisions, including a fixed price provision which will minimize financial risk to Altresco and a bonus/penalty provision, to ensure timeliness and quality of construction. In addition, the record indicates that UE&C has substantial experience in constructing gas-fired combined-cycle projects, with an emphasis on pre-packaged construction.

Further, the record indicates that Altresco has entered into a signed 20-year site lease agreement with GE and a signed interconnection agreement with NEPCo. However, the Company has not provided a signed contract with the LWSC for the provision of treated effluent and potable water and the record does not indicate an alternative source of water. Failure to acquire the planned supply of effluent for plant use could seriously jeopardize the operation of the proposed project. The Company has not provided a written explanation as to why the final agreement is not yet available. Therefore, the Siting Board is not able to determine with any certainty that water would be available. If Altresco finalizes this agreement, the Company will be able to establish that its proposed project is likely to be constructed within applicable timeframes and be capable of meeting performance objectives. Therefore, the Siting Board requires Altresco to provide the Siting Board with a signed copy of the agreement between Altresco and LWSC for provision of treated effluent and potable water.

Accordingly, based on compliance with the above condition that the Company provide the Siting Board with a signed copy of the agreement between Altresco and LWSC for provision of treated effluent and potable water, the Siting Board finds that Altresco will have established that its proposed project is likely to be constructed within applicable time frames and be capable of meeting performance objectives.

The Siting Board has found that Altresco has established that its proposed project (1) upon compliance with the condition relative to power sales in Section II.A.5, above, is likely financiable, and (2) upon compliance with the above condition relative to the provision of treated effluent and potable water, is likely to be constructed within applicable time frames and be capable of meeting performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, Altresco will have established that its proposed project meets the Siting Board'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 Board 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. Enron, 23 DOMSC at 106; EEC, 22 DOMSC at 303-304; 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 detailed pursuant to contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. Enron, 23 DOMSC at 106; West Lynn, 22 DOMSC at 71; Altresco-Pittsfield, 17 DOMSC at 381-382.

Altresco stated that it has selected GE Power Systems Group ("PSG") as the contractor responsible for O&M of the proposed project (Exh. HO-V-8). The Company provided the Siting Board with an executed O&M contract between Altresco and PSG, with a 10-year contract term, dated January 24, 1992 (Exh. HO-V-8).

The O&M contract includes mandatory contract terms which Altresco stated were designed to create incentives to maintain the project's longevity, performance, availability and maximum output without sacrificing safety or environmental considerations (id.; Company Initial Brief at 93). Altresco stated that the operator's reimbursement structure will consist of three parts: direct management costs; operator's fees; and a plant availability bonus (id.). The Company stated that it believes this structure provides the correct incentives for the operator to maintain safe and reliable operation of the facility -- not a disincentive to cut costs in a manner which would create the potential for harmful long-term effects or safety impacts (Exhs. AL-2, at 6-3; HO-V-8).

Altresco provided documentation indicating that PSG has been in the O&M business since 1984 and currently operates nine combined cycle facilities (Exh. HO-V-9). Altresco further stated that, prior to 1984, GE operated and maintained its own facilities for many years (Tr. 3, at 76). In support of its selection, the Company noted that PSG provides O&M services for Altresco's facility in Pittsfield, Massachusetts, and that it has found the quality of PSG personnel and service to be superior (Exh. HO-V-8). Therefore, Altresco asserted that it is confident that PSG has the necessary experience to operate and maintain the proposed facility (Tr. 3, at 77).

In the past, the Siting Council found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreements. Enron, 23 DOMSC at 107; Altresco-Pittsfield, 17 DOMSC at 382. Here, Altresco has provided an executed O&M agreement, complete with bonus, penalty, and incentive provisions similar to those reviewed and approved in prior Siting Council decisions, with PSG, a qualified vendor.

Accordingly, the Siting Board finds that Altresco has established that its proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreement.

b. Fuel Acquisition

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements. Here, Altresco provided a copy of a signed 20-year contract with Union Pacific Fuels, Inc. ("Union Pacific") to supply all the natural gas requirements of the proposed project (Exh. HO-V-11, attach. 11a). The contract establishes a delivery point on the ANR Pipeline Company ("ANR") system (id., attachs. 11a-11f). From this delivery point, a 365-day-per-year firm transportation service would be provided pursuant to contracts or precedent agreements with ANR, CNG Transmission Corporation ("CNG"), and Tennessee (id.). The Company indicated that it reviewed several plans to supply the facility with gas (Exh. AL-2, at 7-3 through 7-5).[164] Altresco stated that the ANR-CNG-Tennessee combination was selected as the route which best satisfies Altresco's criteria (Exh. HO-V-13).

In support of the Company's selection of Union Pacific, Altresco stated that the price at the delivery point was competitive, and in fact superior, relative to the other domestic offers for service (Tr. 7, at 8, 9). Further, when combined with the transportation route which could be made available to the Company, the Union Pacific supply was clearly superior (id.). Altresco added that its contract is advantageous as it has firm gas transportation arrangements and a long term gas supply contract that includes a fixed price escalator with a strong domestic producer (Exh. AL-40, at 10). The Company indicated that both its base rate and the fixed escalator rate are under the current forecasted rates for New England (Tr. 13, at 97).

Altresco acknowledged, however, that two FERC actions are necessary in order to implement the above-described fuel plan (Exh. HO-V-10). Altresco stated that CNG must obtain FERC authorization to construct and operate certain upgrades to its system to transport Altresco's supplies on a firm basis (id.). The Company further stated that CNG would need to construct approximately three miles of thirty-inch pipeline from the end of its mainline system in Albany, New York to a Tennessee system point known as Knox (id.). Altresco estimated that the approximate in-service date would be 1994, and that the schedule could tolerate several months of slippage without delaying the timely completion of the necessary facilities (id.).

The other necessary action, according to Altresco, is for Tennessee to file with the FERC for authorization to construct and operate certain upgrades and extensions of its system to allow the transportation of Altresco's supplies on a firm basis (id.). Specifically,

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164 The Company stated that it used the following set of criteria to select a fuel supply plan for the proposed project: (1) competitive pricing and favorable pricing terms; (2) pipeline route with the fewest regulatory uncertainties; (3) pipeline route that would require a minimum number of new facilities; and (4) reliability of supplier and the suppliers' ability to follow through with a contract (Exh. HO-V-13).

Altresco stated that Tennessee would need to add some compression and construct approximately 2.5-miles of pipeline through the City of Lynn to complete the last section of the gas supply route (id.).[165] Altresco stated that it had considered transporting the gas over the last section to the proposed facility utilizing an existing Boston Gas Company 24-inch pipeline, but concluded, based on its review, that this option would be inferior to the Tennessee option (Tr. 7, at 27-28).[166]

Altresco indicated that the estimated date for the completion of Tennessee construction and commencement of service is December 1994, and that this schedule would also tolerate some slippage regarding the date of the FERC authorization without causing a project delay (Exh. HO-V-10). The Company asserted that the time frame considered for the FERC process does take into account potential delays in the FERC permitting process so that the completion of facility construction nearly coincides with the approval and subsequent completion of the pipeline construction (id.; Tr. 7, at 37, 40-41; Company Initial Brief at 98-99). Should an unforeseen obstacle to the FERC licensing process arise, Altresco stated that it would depend on a combination of delivery services from Boston Gas Company, including

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165 Altresco stated that the proposed route through Lynn which it identified for the Siting Board was superior for the final section of the pipeline (Exh. HO-V-33). Altresco asserted that the primary advantage of utilizing this route is that a majority of the route will utilize an existing ROW that has been dedicated to public uses for many years, resulting in a minimal impact to the surrounding land uses and the environment (Tr. 7, at 20-21). Altresco noted, however, that since the pipeline will be the subject of a Tennessee filing with the FERC, the final approved routing could be different than that presented to the Siting Board (id., at 20). Environmental impacts of the fuel supply are discussed in Section III.C.2.e., below.

166 Altresco stated that the 24-inch Boston Gas Company pipeline would have to meet Tennessee specifications, as the goal of the Company would be to have Tennessee operate the pipeline, however, Boston Gas does not operate their pipelines over 200 pounds pressure while the interstate pipeline systems do operate above such pressure (Tr. 7, at 28-29). Altresco stated that expensive testing would be necessary to determine if the pipeline could handle the pressure (id., at 27). Therefore, the Company determined that the alternative of the Tennessee extension was more economic (Tr. 7, at 27).

interruptible supply, which, while not dependable for a twenty year span, would be sufficient and available on a temporary basis for a year or two (Tr. 7, at 40-41).

In the event of a gas supply interruption, Altresco indicated that its fuel strategy provides for a backup supply of fuel -- ultra low sulphur (.05%) No. 2 fuel oil (Exh. HO-V-16). Altresco's Air Plan Application to the DEP proposes to limit the use of low sulphur oil to approximately five full days of 100 percent oil use (id.). The Company argues that this five-day supply should be more than enough to cover a worst case scenario (Tr. 7, at 15). Here, Altresco asserted that interstate pipeline failures of the type that would curtail transportation of gas to the facility are rare, particularly in well maintained system areas such as the Northeast (id.). Based on his experience, Altresco's witness, Mr. Corbett stated that should such a problem occur, the system would be easily repaired and service restored in less than five days (id.).

Altresco stated that there is no need for a long-term backup fuel contract, as oil is sold on a commodity basis which would enable Altresco to shop around for the best price at the time the purchases are necessary (id., at 9-10). The Company also stated that based on its corporate experience in operating the Pittsfield facility and resultant familiarity with the fuel oil distribution network in the Northeast, it has established the contacts and experience to ensure that spot contracts for the purchase of fuel oil will be a more than adequate source of supply for the limited quantities that may be needed at the facility (Exh. AL-9, at 4). Altresco further stated that, at this time, it expects to rely upon an established relationship with Sprague Energy Company ("Sprague"), located in Portsmouth, New Hampshire, -- the current supplier for Altresco Pittsfield,[167] -- for this backup fuel supply (Tr. 7, at 10-11, 62). However, Altresco indicated that in a competitive market there may be another supplier that can provide a comparable or better fuel supply service than Sprague (id.).

Regarding the storage of its backup oil supply, Altresco stated it has considered two options, and that it plans to utilize bulk storage off-site at the location of Altresco's chosen

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167 The Company indicated that the Altresco Pittsfield facility utilizes a Sprague terminal located in Albany; however, for the proposed facility, the Sprague terminal in Portsmouth would likely be used (Tr. 7, at 10 and 62).

fuel oil supplier (Exh. HO-RR-26; Tr. 7, at 61; Tr. 13, at 52).[168] The Company indicated that this option would also require an on-site tanker truck capable of storing approximately 10,000 gallons of fuel oil, enough to provide the plant's total fuel requirement for about one hour (Exh. HO-RR-48B). The Company stated that it would utilize GE's fuel oil off-loading bay adjacent to the Altresco Lynn facility (Exh. HO-RR-26). Altresco's witness, Mr. Corbett, asserted that the Company would seek fuel oil supply contracts which would provide for delivery from the supplier's terminal to the plant, including responsibility for making available the proper number of delivery trucks to meet Altresco's needs (id.). Additionally, Mr. Corbett indicated during testimony that numerous fuel oil suppliers are located in Lynn, and that the suppliers' close proximity to the proposed facility is desirable (Tr. 7, at 10-11).

In reviewing a project's fuel acquisition strategy, the Siting Board 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. ENRON, 23 DOMSC at 118; EEC, 22 DOMSC at 309; Altresco-Pittsfield, 17 DOMSC at 384-389.

Here, Altresco has described a nearly final primary fuel supply option and various backup fuel supply options for the proposed facility. In considering the primary gas supply, the Siting Board acknowledges that while final FERC regulatory action regarding authorization for the CNG transmission upgrades and Tennessee upgrades and extensions is still pending, with the potential for a number of regulatory delays, Altresco has articulated a reasonable long-term primary fuel supply plan. Further, the fuel supply contract terms for cost and a 365-day firm supply ensure that the fuel supply is likely to be least-cost. Additionally, as a primary fuel contingency option, a combination of short-term delivery services from Boston Gas would enable the facility to come on-line upon completion should a

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168 Altresco stated that originally its first option was to store oil on-site by leasing an 800,000-gallon tank owned by GE (Exh. HO-RR-26; Tr. 7, at 83; Tr. 4, at 33). However, the Company stated that it has not negotiated an agreement with GE to lease the storage tank (Tr. 13, p. 52).

regulatory delay occur inhibiting timely FERC authorization of the gas line upgrades and extensions.

With respect to backup fuel oil supply plans, Altresco's preferred option involves acquiring bulk, off-site storage and utilizing a tanker on-site capable of storing approximately 10,000 gallons of fuel oil, enough for approximately one hour of facility operation.[169] In previous cases, the Siting Board has expressed a preference for on-site fuel storage, whether for a primary or backup fuel supply. Enron, 23 DOMSC at 118; EEC, 22 DOMSC at 309; Altresco-Pittsfield, 17 DOMSC at 384-389.

However, in the recent Enron decision, the Siting Board did accept a backup fuel supply plan which did not include on-site storage. 23 DOMSC at 118-119. The Company has developed a backup plan that utilizes fuel tanker trucks with direct off-loading of oil to the facility. In addition, Altresco has indicated that interruptions in pipeline gas supply deliveries are rare. However, the facility is equipped to store only one hour of back-up fuel supplies on-site. The Siting Board notes that the close proximity to a large number of fuel oil suppliers in the area of the project provides assurance that the backup fuel supply can be implemented in a timely manner. The Siting notes that with only one hour of fuel oil available on site and the planned supplier in Portsmouth, New Hampshire, the Company may have to utilize a local company as well, to ensure continuous operation. Therefore the Siting Board finds that there are sufficient options available to the company to ensure that the back-up fuel supply will be available if needed.

Finally, the Company has contracted for a firm, long-term supply and transportation arrangement at an attractive base price with fixed escalators, ensuring that the cost of the Altresco gas supply would be limited in its volatility, both in price and volume.

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169 The Siting Board understands based on information contained in Section III.C.2.h., below, that Altresco would comply with all applicable environmental and safety regulations for the off-site storage with a 10,000-gallon on-site tanker. Therefore, any risk of adverse environmental impacts should be minimal.

Accordingly, the Siting Board finds that Altresco has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the term of its power sales agreements.

The Siting Board has found that, at this time, Altresco (1) has established that the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreement, and (2) has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the terms of its power sales agreements. Accordingly, the Siting Board finds that Altresco has established that its proposed project meets the Siting Board's second test of viability.

4. Conclusions on Project Viability

The Siting Board has found that, (1) upon compliance with the above conditions, Altresco will have established that its proposed project 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 PPA's.

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

D. Consistency with the Policies of the Commonwealth

1. Standard of Review

Massachusetts General Laws c. 164, §§ 69I and 69J require that plans for construction of new facilities be consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth.

In MASSPOWER, the Siting Council first stated that it would place greater emphasis on determining whether a non-utility developer's proposed project is consistent with the resource use and development policies of the Commonwealth. 20 DOMSC at 352. In its first facility review after MASSPOWER, the Siting Council further noted that, although it had already considered many aspects of a project's consistency with the resource use and development policies of the Commonwealth in its reviews, the Siting Council recognized that its reviews 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. West Lynn, 22 DOMSC at 60. See also, EEC, 22 DOMSC at 280. Therefore, the Siting Council found that it was appropriate to evaluate a proposed project's attributes relative to a broad range of resource use and development policies. West Lynn, 22 DOMSC at 56-57. See also, Enron, 23 DOMSC at 82. In West Lynn, the Siting Council found that the general types of policies identified by the proponent in that case -- energy, environmental, and economic -- are the relevant resource use and development policies to be considered. 22 DOMSC at 60. See also, EEC, 22 DOMSC at 93. In City of New Bedford, the SJC noted, however, that the Siting Council's review of a project's consistency with resource use and development policies should not elevate consistency with those policies and their related benefits above the primary statutory objectives of providing a necessary energy supply with a minimum environmental impact at the lowest possible cost (413 Mass. at 490).

Here, the Siting Board reviews, for the first time since City of New Bedford, a proposed project for its consistency with the policies of the Commonwealth. In so doing, the Siting Board emphasizes that its intention is not to elevate benefits associated with policies above the primary statutory objectives, but to ensure that a proposed project which meets the statutory objectives is consistent with the policies of the Commonwealth. The Siting Board notes that the Commonwealth and its agencies set forth energy, environmental, economic, and other policies to further certain goals. Thus, the Siting Board considers the extent to which the Company's proposed project furthers specific, identifiable policy goals as part of its evaluation of the project's consistency with current Massachusetts policies. The Siting Board may consider project-specific benefits which will contribute to policy goals in this evaluation.[170]

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170 In EEC (Remand), the Siting Board noted that benefits not related to the energy supply, while not relevant to the review of need for a proposed project, may still be considered with respect to the requirement of G.L. c. 164, §§ 69I and 69J that proposals to construct energy facilities be consistent with the current health, environmental protection, and resource use and development policies as adopted by the (continued...)

In demonstrating consistency with Massachusetts policies, the Company may identify specific policies and show how its proposed project will further the specific goals of each identified policy. The Siting Board may also require a Company to address specific policies of the Commonwealth and show how its proposed project is consistent with, or furthers, such policies.[171] In accordance with the above standard and G.L. c. 164, §§ 69I and 69J, the Siting Board, in this section, assesses the consistency of Altresco's proposed project with the current health, environmental protection, and resource use and development policies of the Commonwealth.

Altresco argued that its proposed project is consistent with the resource use and development policies of the Commonwealth (Company Initial Brief at 77). In support, Altresco identified the proposed project's consistency with policies in the following three general categories: (a) energy policies; (b) environmental policies; and (c) economic policies (Exh. HO-CP-1). Altresco also identified a number of specific benefits which the proposed project would provide which would further specific Massachusetts policies in these categories.

2. Energy Policies

Altresco asserted that, consistent with energy policies of the Commonwealth, the proposed project would utilize an existing industrial site for the cogeneration facility, and contribute towards greater fuel diversity and the achievement of stable energy prices and

[170](...continued)
Commonwealth. Id., 187, n. 272.

[171] The Siting Board notes that it is important to focus on up-to-date pronouncements and decisions of relevant state agencies when assessing the consistency of a proposed 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. Enron, 23 DOMSC at 87; EEC, 22 DOMSC at 103.

energy supplies through the use of natural gas as the primary fuel supply (Exh. AL-2, at 11-2; Company Initial Brief at 77-78). With respect to power sales[172], the Company stated that the cost of energy from the proposed project would be less than the avoided costs of the potential buyers of its power in Massachusetts (Exh. AL-2, at 9-37). The Company provided the Siting Board with an avoided cost analysis to substantiate its claim (Exh. AL-32).

The Company provided the Siting Board with a report entitled "Developing Energy Resources: A Five Point Plan" ("MEOER Report") written by the former Massachusetts Executive Office of Energy Resources in December of 1988, now the Division of Energy Resources ("DOER") (Exh. HO-CP-1).[173] Altresco stated that the MEOER Report contains a major policy recommendation supporting cogeneration projects, and enumerates specific attributes and benefits of such cogeneration projects including (1) the use of existing commercial and industrial sites, (2) improvement of the competitiveness of Massachusetts commercial and industrial enterprises through an energy related reduction in the cost to produce goods and services, and (3) where the proposed facility will utilize an existing industrial site, the ability of such cogeneration to minimize environmental impacts normally associated with new facility construction (id.).

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172 As noted above, Altresco provided the Siting Board with evidence of a signed PPA with Commonwealth Electric for 25 MW and Altresco's status as the sole project in BECo's RFP 3 Award Group for 132 MW (see Section II.A.2, above, for a further discussion of power sales) (Exhs. HO-MB-1; HO-MB-12S; HO-RR-30).

173 Altresco stated that, during the course of the proceeding, then DOER Commissioner Paul W. Gromer had informed Altresco that the MEOER Report -- three years old at the time -- continued to accurately represent the Commonwealth's energy policies, and remained the most comprehensive document available which addressed such policies (Exh. HO-CP-1).

The Siting Board notes that a DOER Report "The Massachusetts Energy Plan" ("DOER Report") was released in April of 1993, after the record was closed in this proceeding. Further, the Siting Board recognizes that the DOER Report contains recommendations consistent with the MEOER Report including the development of cogeneration power plants.

Regarding the project's use of natural gas as the primary fuel supply, Altresco stated that, in a previous decision (Enron, 23 DOMSC at 87), the Siting Council found that "the use of natural gas as fuel will help to diversify the Commonwealth's fuel supply mix for electricity generation and thus will enhance the reliability and cost stability of the Commonwealth's energy supply" (Exh. HO-CP-1). Altresco provided the Siting Board with data indicating that the proposed project would diversify the Commonwealth's fuel supply portfolio by increasing its use of natural gas for electric generation by approximately 25 percent (Exh. HO-MB-6).[174]

The record indicates that the proposed project would (1) be located on an existing industrial site; (2) utilize cogeneration technology, and (3) burn natural gas as its primary fuel supply, all of which are consistent with the Commonwealth's current energy policies. With respect to the supply of reliable and economic power, the Siting Board notes that Altresco has provided evidence of (1) a signed PPA between it and Commonwealth Electric for 25 MW, and (2) the proposed project's status as the sole project in BECo's RFP 3 Award Group for 132 MW. The sum of the above totals 157 MW, an amount equal to 92 percent of the proposed project's power capacity. Further, Altresco has provided avoided cost analyses for various utilities, including Commonwealth Electric and BECo, which demonstrate that the proposed facility is likely to reduce costs for Massachusetts electricity customers, consistent with state policy supporting the addition of QF resources to the energy supply of the Commonwealth. However, the Siting Board notes that, with the exception of the 25 MW contract with Commonwealth Electric, the magnitude of the specific economic benefits remains in question.

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174 Altresco stated that in 1989, natural gas constituted approximately 12 percent of the overall energy input for electric generation in the Commonwealth, and added that if the proposed project had been on line in 1989, it would have increased the diversity towards natural gas use in the Commonwealth's electric generation sector to 15 percent of the overall energy input supply mix, an increase in natural gas use of 25 percent (Exh. HO-MB-6).

Accordingly, the Siting Board finds that the proposed project is consistent with the broad policies of the Commonwealth relating to the development of cogeneration and the addition of cost-efffective QF resources to the energy supply.

3. Environmental Policies

Altresco argued that, consistent with environmental policies of the Commonwealth, the proposed project would (1) minimize air emissions by utilizing natural gas, state-of-the-art generation and related emission control equipment, (2) reduce both organic and hydraulic loading to the LWSC wastewater treatment plant, and (3) benefit the Rumney Marsh Area of Critical Environmental Concern ("ACEC") by diverting existing storm water discharges at the GE site from the Saugus River, and (Exh. HO-CP-1; Company Initial Brief at 6-7, 69-70, 80).

With respect to air emissions, the Siting Board finds in Sections III.C.2.a.(2).(a) and III.C.4, below, that with some additional mitigation of CO_2 impacts, the air quality impacts of the proposed facility would be minimized consistent with minimizing cost. Further, in Section II.A.4.e, above, the Siting Board found that Altresco demonstrated that the proposed project: (1) would provide short-term air quality benefits to Massachusetts by providing an initial net reduction of air pollutant emissions from generating units in Massachusetts;[174A] and (2) would reduce net SO_2 emissions and help minimize emissions of other air pollutants in the Lynn area by displacing emissions from existing GE steam production operations.

In addition, as discussed in Section III, below, the proposed project would reduce the existing organic and hydraulic loading through the LWSC wastewater treatment plant to Lynn Harbor, and divert existing storm water discharges at the GE site which are currently directed into the Saugus River within the Rumney Marsh ACEC. Both of the above effects would result in a net improvement relative to existing levels of discharge to Lynn Harbor and the Saugus River/Rumney Marsh ACEC.

Accordingly, the Siting Board finds that the proposed project is consistent with the broad policies of the Commonwealth relating to minimizing or mitigating environmental impacts. The Siting Board notes, however, that in future cases project proponents will be expected to identify specific environmental policies for consideration.

4. Economic Policies

Altresco stated that, consistent with economic policies of the Commonwealth, the proposed project would (1) produce low cost power for electricity customers, (2) improve the competitiveness of GE through the provision of low cost steam, and (3) provide other economic benefits to GE, to the City of Lynn, and to the local economy (Exhs. AL-2, at 11-2; AL-17; HO-MB-16; Company Initial Brief at 73,75).

The Company asserted that the following specific economic benefits in Massachusetts would be realized by GE and the City of Lynn: (1) a supply of steam, approximately 480 million pounds annually (55,000 pounds/hour ("pph")) at a significantly reduced cost to GE; (2) lease payments to GE for use of the 5.7 acres of proposed project site within the GE Riverworks facility; and (3) annual payments of approximately $250,000 to LWSC for the purchase of treated wastewater effluent (Exh. AL-17; Exh. HO-MB-16; Company Initial Brief at 75). Altresco argued that in the West Lynn Decision (22 DOMSC, at 63), the Siting Council previously found that a generation project which will enhance the productivity and competitiveness of an established manufacturing firm is consistent with state policies relating to economic development (Company Initial Brief at 79).

With respect to steam sales, Altresco asserted that the proposed project would improve the competitiveness of GE through the utilization of cogeneration technology and the sale of steam to GE at a price less than GE's current cost of producing steam (Exh. HO-CP-1). Altresco asserted that its analysis demonstrates a reduction of approximately 42.3 percent in net present value of the cost of steam purchased by GE over the 20 year life of the contract, relative to the cost to GE for producing all its own steam (Exh. AL-32).

With respect to its purchase of wastewater effluent, Altresco argued that the payments will benefit all participants in the regional treatment facility, and that such payments have been previously recognized by the Siting Board as a significant economic benefit to the affected local community (Company Initial Brief at 75). Altresco stated that it will pay the

LWSC approximately $250,000 per year for treated effluent corresponding to approximately 1,000,000 gpd, and noted that this amount is nearly six times larger than the amount of effluent purchase reviewed by the Siting Board in West Lynn (Exh. AL-1).[175]

Finally, Altresco argued that the construction of the facility will provide economic benefits in the form of additional employment and tax revenues to the region, including several hundred construction related jobs (Company Initial Brief at 73). Altresco stated that the project would additionally provide 30 permanent positions for operations and maintenance personnel at the facility (Exh. HO-MB-7).

The Siting Board previously has accepted a reduction of steam user costs, based on a steam sales agreement, as evidence of important economic benefits to Massachusetts. West Lynn, 22 DOMSC at 41-42; Altresco-Pittsfield, 17 DOMSC at 367-369. Such savings are made possible, in part, by energy efficiencies inherent in cogeneration technologies as compared to possible alternative production of the same amounts of process steam and electricity in separate facilities. Altresco-Pittsfield, 17 DOMSC at 367-368. As such, the savings to the steam host represent a real economic benefit rather than simply a transfer of costs from the steam host to the project proponent. West Lynn, 22 DOMSC at 41-42.

Here, Altresco claims that the steam cost savings realized will approach a 50 percent reduction in the cost of providing approximately 55,000 pph of steam-based energy for GE (Exh. AL-2, at 4-2). In a previous case, the Siting Board accepted a similar percentage of cost reduction, involving just under half the amount of steam-based energy to be provided by Altresco as evidence of a real economic benefit to the steam host. West Lynn, 22 DOMSC at

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174A The Siting Board also found that Altresco had not demonstrated that the proposed project would provide long-term air quality benefits based on such reductions. However, we recognize that the proposed project may help minimize long-term air pollutant emissions of generating units in Massachusetts by helping to avoid or reduce any net increases in such emissionss. See Section II. A. 4. e., above.

175 The Siting Board notes that, to date, Altresco has not provided it with a signed wastewater reuse agreement.

41-42.[176] Altresco's analysis indicates that a significant and measurable savings in steam costs is likely to be realized by GE, improving its competitiveness and therefore benefitting the Massachusetts economy through tax revenue and employment effects.

With respect to the land lease payments, the Siting Council previously found that such an arrangement may provide little or no net benefit to Massachusetts, given that a steam host, in the absence of the lease arrangement, could make alternative economic use of a proposed cogneration project site or lease the site to another user. West Lynn, 22 DOMSC at 45. Here, Altresco has not demonstrated that GE would be unable to derive value from an alternative use of the proposed site.

Regarding payments to LWSC for wastewater effluent, the Siting Council previously held that, with a signed contract for effluent purchases, a project proponent could demonstrate that such an arrangement would provide a real economic benefit to the wastewater treatment plant operator and the community it serves. Id. at 44-45. Here, however, Altresco has not provided the Siting Board with a signed contract with LWSC for the proposed purchase of wastewater effluent.

Regarding the Company's claims that the proposed facility would create both temporary and permanent jobs, the Siting Board 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. The positive impacts to the local economy that are likely to result from the construction and operation of the proposed facility, while welcome and helpful, are not unique or unusual, based on any specific characteristics of the proposed project. 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.

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176 The Siting Board notes that, in terms of the percentage of steam costs, the anticipated savings to the steam host in that previous case and Altresco's steam host are approximately the same.

Overall, the Company has established significant economic benefits resulting from expected project steam sales. Based on the foregoing, the Siting Board finds that Altresco has established that Massachusetts would receive clear economic benefits as a result of the proposed project, and that the proposed project is consistent with the broad economic policies of the Commonwealth. The Siting Board notes, however, that in future cases project proponents will be expected to identify specific economic policies for consideration.

5. Conclusions on Consistency with Policies

In light of the above, the Company has adequately demonstrated that the proposed project would further a number of broadly representative state policies relating to energy, environmental protection, and economic development. Accordingly, the Siting Board finds that the Company has established that the proposed project is consistent with current health, environmental protection, and resource use and development policies of the Commonwealth.

E. Conclusions on the Proposed Project

The Siting Board has found that (1) New England needs at least 170 MW of additional energy resources from the proposed project for reliability purposes in the year 2000 and beyond, and at least 170 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000 or later; and (2) Massachusetts needs at least 170 MW of additional energy resources from the proposed project for reliability purposes in the year 1997 and beyond. However, the Siting Board found that submission of (1) a signed and approved contract with BECo for 132 MW, or (2) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, will be sufficient to establish that the proposed project will provide a necessary energy supply for the Commonwealth.

The Siting Board has also found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. In addition, the Siting Board has found that the proposed project, (1) upon compliance with the conditions in Section II.C.2., 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 PPA's. Finally, the Siting Board has found that the proposed project is consistent with current health, environmental protection, resource use, and development policies of the Commonwealth.

III. ANALYSIS OF THE PROPOSED FACILITIES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164 §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H and J. Further, G. L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Board requires a 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. 1993 BECo Decision at 27.

A. Description of Proposed Facilities

Altresco proposes to construct a 170 MW natural gas-fired combined-cycle cogeneration facility in the City of Lynn (Exh. AL-2, at 1-1). The 5.7-acre site is located in the southwestern quadrant of the 223-acre GE River Works complex, located between Route 107, the Lynnway and the Saugus River (id.; Exhs. HO-E-1, Fig. 3.1-2; HO-E-4, at 2-1). The facility would be located within both an existing GE structure, referred to as Building 64, and a newly constructed building adjacent to Building 64 (Exhs. AL-2, at 3-1; HO-E-1, at 2-3).[177]

The major components of the proposed project include three GE Series 6000 gas turbine generators, three enclosed HRSGs, a single condensing turbine generator with a water cooled condenser, a wet mechanical draft evaporative cooling tower, and three stacks approximately 200 feet high (Exhs. HO-E-4, at 2-2; HO-E-36S). Additional components include an ammonia storage tank, a 500,000 gallon municipal effluent storage tank, and a 100,000 gallon demineralized water storage tank (Exh. HO-RR-68). NOx emissions would be controlled through the use of advanced dry low-NOx combustors and SCR (Exhs. HO-E-1, at 5-1; HO-E-60).

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177 The Company stated that the power generation equipment, including the gas turbine generators and the HRSG, would be housed in a new, 79-80 foot high building (Exhs. HO-E-4, at 2-3; HO-E-36S).

The proposed facility would be powered by natural gas delivered through a new 16-inch, 2.5-mile pipeline to be constructed by Tennessee, with distillate oil as backup fuel (Exhs. HO-E-1, at 2-1; AL-29; HO-V-10). A natural gas interconnection line of approximately 1,800 feet would be constructed between a new sales meter station on the Tennessee pipeline and natural gas compressors within the facility (Exh. HO-E-1, at 3-8). The proposed facility would be capable of providing GE with at least 55,000 lb/hr of steam for process and heating use (Exhs. AL-2 at 3-1; HO-E-33, at A-1). This steam would be transported via an above-ground 1,450 foot, 12-inch diameter line (Exh. HO-RR-37). The electricity generated by the proposed facility is to be transmitted off-site via two new 115 kV above-ground 1,600-foot interconnection lines, located over existing parking areas on the GE site, to existing utility lines (Exh. HO-E-1, at 3-7).

The proposed facility would cost approximately $182 million in 1996 dollars (Exh. HO-RR-88).

B. Site Selection Process

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. 1993 BECo Decision, EFSB 90-12/90-12A at 27; Berkshire Gas Company, 25 DOMSC 1, 48 (1992) ("1992 Berkshire Decision"); NEA, 16 DOMSC at 381-409 (1987). In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it 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. 1993 BECo Decision, EFSB 90-12/90-12A at 27; 1992 Berkshire Decision, 25 DOMSC at 48; MASSPOWER, 20 DOMSC at 373-374, 382; Berkshire Gas Company (Phase II), 20 DOMSC 109 at 148-149, 151-156 (1990) ("1990 Berkshire Decision"). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.[178] 1993 BECo Decision, at 28; 1992 Berkshire Decision, 25 DOMSC at 49; NEA, 16 DOMSC at 381-409. In past decisions, the Siting Council did not require a noticed alternative site in cases involving proposals to construct cogeneration facilities if the cogeneration proponent (1) had a steam sales agreement with existing steam purchaser(s) sufficient to qualify it for QF status; and (2) had a proposed site fully within the property boundaries of the principal steam host. EEC, 22 DOMSC at 315; West Lynn, 22 DOMSC at 78; MASSPOWER, 20 DOMSC at 382.[179]

However, the Siting Board notes that proposed sites or routes located in the coastal zone as defined under the Massachusetts Coastal Zone Management ("CZM") program and the Coastal Zone Management Act, 16 U.S.C. § 1453, are subject to additional regulatory requirements.[180] The Siting Board is the designated energy facilities siting agency under the CZM program pursuant to 980 CMR 9.01ff. These regulations implement the CZM program as adopted by the Secretary of Environmental Affairs under G.L.c. 21A, §§ 2, 3, and 4.

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178 When a facility proposal is submitted to the Siting Board, 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 Board's review. In reaching a decision in a facility case, the Siting Board can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Board, 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.

179 As noted previously, all facility petitions before the Siting Board will be reviewed consistent with all legal and decisional precedents established by the Siting Council until superseded, revised, rescinded, or cancelled in accordance with law by the Siting Board. Reorganization Act, §46.

180 In the instant case, the site proposed by the Company is located in the coastal zone as defined by the CZM Program and the CZM Act and regulations, 16 U.S.C. § 1453, 980 C.M.R. 9.00 (Exh. AL-2, at 12-8).

Under the Siting Board's Coastal Zone Facility Site Selection, Evaluation, and Assessment regulations, when a facility is proposed for coastal siting, the petitioner must "propose, evaluate and compare at least one alternative site." 980 CMR 9.02(1)(a). Further, when a facility proposed for coastal siting is not a coastally dependent energy facility (see 980 CMR 9.01(2)), the alternative site to be proposed, evaluated and compared "shall be inland of the coastal zone." 980 CMR 9.02(1)(a). Any alternative site "shall be reasonably determined and demonstrated to be capable of development and licensing or approval by all federal, state, regional and local agencies" Id. The site evaluation and comparison must "include a justification of the necessity for or advantage of coastal siting along with an explicit definition of the process developed to compare alternative sites." Id.[181]

In the sections below, the Siting Board reviews the Company's site selection process, including Altresco's development and application of siting criteria as part of its site selection process, and the consistency of the Company's proposal with the Coastal Zone facility regulations.

2. Development of Siting Criteria

Altresco stated that it developed and applied a reasonable set of criteria which demonstrates that it has not overlooked or eliminated any clearly superior alternative sites (Exh. AL-2, at 12-2; Company Initial Brief 105-116). The Company further asserted that the proposed site minimizes cost and environmental impacts, while ensuring reliability of supply (id.). Altresco stated that it identified a broad range of steam host opportunities, and selected the steam host based on cost, reliability and environmental impacts (Company Initial Brief at 116). The Company indicated that it then selected nine potential facility sites in the vicinity of the steam host and subjected them to a scoring system based on environmental and business sensitivities (id.).

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181 These requirements apply only to proposed sites located in the coastal zone as defined under the Massachusetts CZM program.

a. Description

Altresco developed two sets of criteria, one set of criteria for selecting a steam host, and a second set of criteria for selecting a site for the facility in the vicinity of the steam host (Exh. AL-2, at 12-2 to 12-7).

The Company stated that it developed six criteria to identify and select an appropriate steam host for its facility, specifically that the steam host should: (1) have a substantial steam demand; (2) be a financially stable company willing to make a long-term commitment to the proposed project; (3) be located in an industrially zoned site with a sufficient amount of unused property and suitable environmental characteristics;[182] (4) have easy access to a fuel supply; (5) have access to a water supply; and (6) have access to a transmission system (id. at 12-2 and 12-3).[183]

With respect to the selection of a site in the vicinity of the steam host, Altresco stated that it developed multi-level criteria for evaluating business and environmental factors for alternative sites (id. at 12-6). The Company further explained that the site review process was based on the development of decision criteria that focused on land use and environmental concerns as well as facility development and operations (id.).

The Company stated that a local realty firm was retained to identify sites outside of GE ownership, using the following parameters: the site must be (1) located outside of the coastal zone; (2) located five miles or less from the steam host; (3) at least five acres in size; and (4) located within industrial land use zones or zones where special use zoning could be obtained (id. at 12-9).

Altresco stated that it used the following site selection criteria in evaluating alternative sites in the vicinity of GE River Works: (1) air quality, including: (a) permit considerations,

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182 The Company listed environmental characteristics as features which would ensure acceptable effects on air quality and dispersion, water quality, and noise and visual impacts (Exh. AL-2, at 12-3).

183 Altresco applied its steam host selection criteria and chose GE River Works as the steam host. The Siting Board reviews the application of the steam host selection criteria in the following section.

(b) non-attainment concerns, and (c) impacts of stack emissions; (2) water/wastewater, including: (a) management of water treatment sludge, (b) permit considerations for discharges, and (c) sensitive habitat along ROWs; (3) land resources, including: (a) compatibility with existing land resources, (b) sensitive habitats or species, and (c) regulatory considerations; (4) noise, including (a) sensitive receptors, and (b) regulatory considerations; (5) visual impacts, including: (a) sensitive receptors, (b) compatibility with existing visual environment, and (c) impact on scenic views or vistas; (6) health and safety, including (a) sensitive receptors to accidental releases, and (b) emergency response capabilities; (7) steam transmission to host, including: (a) distance to interconnect point, (b) impact on abutters, (c) land use compatibility, and (d) highway, rail and river crossing; (8) electric transmission routes, including: (a) distance to interconnect points, (b) impact on abutters to ROW, (c) land use and zoning along ROW, and (d) highway, rail and water crossing; (9) water supply availability, including: (a) distance to interconnect for supply, (b) distance to outfall for discharge/type, (c) land use and zoning along ROW, and (d) highway, rail and water crossing; and (10) zoning and land use, including: (a) compatibility with existing zoning or special use industrial applications, (b) compatibility with existing and proposed land use plans, and (c) compatibility with abutters' land use (Exh. AL-3, Table 12-1).[184]

The Company developed a scoring process for the criteria, whereby each of the ten alternative site criteria were assigned a ranking of zero through two where zero indicated unfavorable, one indicated neutral, and two indicated favorable for siting purposes (Exh. Al-2, at 12-7). Altresco indicated that this scoring is only related to the site selection criteria and that no scores were developed for the steam host criteria (Exh. HO-S-3).

b. Analysis

In previous decisions regarding cogeneration facilities, criteria such as those developed by Altresco were found to be acceptable for use in the preliminary identification and

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184 Of the ten siting criteria, one through six are identified by the Company as environmental sensitivities and seven through ten are business factors that result in differential costs (Exhs. AL-2, at 12-7; AL-3, Table 12-1).

evaluation of steam hosts. EEC, 22 DOMSC at 318-320; West Lynn, 22 DOMSC at 82; MASSPOWER, 20 DOMSC at 376-379; Altresco-Pittsfield, 17 DOMSC at 391-393. However, the Siting Board notes that the combination of environmental characteristics with zoning and site access requirements in one criterion serves to dilute the importance of two types of distinct criteria.

The Siting Board further notes that an additional area that warrants consideration is the demand for electricity either on a local or sub-regional basis. In two recent Siting Board reviews, criteria that addressed locating in an area with a need for electrical generation were applied prior to considering overall steam host criteria.[185] EEC, 22 DOMSC at 318; West Lynn, 22 DOMSC at 81. In light of the variety of potential steam hosts, inclusion of the above-mentioned criteria would likely enhance the steam host selection process.

In regard to its development of site selection criteria for identifying and evaluating possible sites in the vicinity of the steam host, the Company has included and considered a broad array of criteria which addresses the critical issues associated with the siting of power plants. The Siting Board notes that in previous decisions the Siting Council accepted criteria such as those developed by Altresco, and that the criteria are thus consistent with the site selection criteria which have been previously found to be appropriate for cogeneration facilities. Enron, 23 DOMSC at 127; EEC, 22 DOMSC at 321; West Lynn, 22 DOMSC at 84; MASSPOWER, 20 DOMSC at 378-379; Altresco-Pittsfield, 17 DOMSC at 391-393.

In regard to the assignment of numerical values to the site selection criteria, the Siting Board notes that both sets of criteria in fact are all weighted equally, and that it is Altresco's scoring mechanism that serves as the basis for ranking various sites under each siting criterion. The Siting Board also notes that the Company identified a reasonable scoring system for the siting criteria, thereby addressing one of the Siting Council's concerns raised in previous decisions regarding the absence of numerical values for the weighting of site

[185] The Siting Board notes that Altresco addressed the need for power as it relates to site location in the context of determining the size of the project (Exh. HO-S-1). The Company stated that it reviewed economies of scale in relation to the power market and QF capabilities (id.).

selection criteria. 1993 BECo Decision at 49; Enron, 23 DOMSC at 127; EEC, 22 DOMSC at 321; West Lynn, 22 DOMSC at 83; MASSPOWER, 20 DOMSC at 378-379; Altresco-Pittsfield, 17 DOMSC at 391-393.

However, the Siting Board reiterates the need for some degree of weighting of siting criteria. 1993 BECo Decision at 49; Enron, 23 DOMSC at 127; EEC, 22 DOMSC at 321; West Lynn, 22 DOMSC at 83; MASSPOWER, 20 DOMSC at 378-379; 1990 Berkshire Decision, 20 DOMSC at 161-162. In requiring the assignment of weights or values, the Siting Board does not suggest that such weights and values can or should operate as a substitute for judgment. Instead the Siting Board recognizes that judgment inherently requires the assignment of some weights to specific criteria, and that our review of such weights provides us with the means to determine whether a company has used appropriate judgement and applied its criteria consistently.

Accordingly, the Siting Board finds that Altresco has developed a minimally acceptable set of criteria for identifying and evaluating potential steam hosts and a reasonable set of criteria for identifying and evaluating potential facility sites.

3. Application of Siting Criteria

a. Description

Altresco stated that the initial concept of the project was based on continuing the Company's working relationship in the Northeast with a GE steam host (Exh. HO-S-1). The Company stated that it selected natural gas as the fuel of choice due to its availability and proximity to GE facilities in the Northeast, and because it compared favorably to oil and coal for transportation, storage and environmental limitations (id.).

The Company indicated that GE had conducted an investigation of the feasibility of cogeneration at all of its major facilities and had identified three priority facilities, GE Pittsfield, GE Lynn (encompassing both GE River Works and GE West Lynn), and GE

Selkirk, New York (Exh. HO-S-17).[186] Altresco stated that in addition to the priority GE facilities, four other GE sites were selected by the Company for review -- GE Schenectady, New York; GE Evandale, Ohio; GE Fitchburg, Massachusetts; and GE Syracuse, New York (Exh. HO-S-18S). Altresco also identified four steam hosts outside of the GE network -- Becket Paper of Hamilton, Ohio; Revere Brass of Revere, New York; Brandeis University of Waltham, Massachusetts; and Bristol Meyers of Syracuse, New York (Exh. HO-S-2S).

Altresco stated that it applied its six steam host criteria to six of the GE facilities and the four non-GE facilities (Exh. HO-S-18S). The Company asserted that GE River Works met all of the criteria, and all of the competing steam hosts were rejected for various reasons, including insufficient steam demand and poor gas transportation access (Exhs. AL-2, at 12-2; HO-S-2S; HO-S-18S).[187]

With respect to the selection of an appropriate site for the facility in the vicinity of the steam host, as noted above, Altresco limited the geographic area to within a five mile radius

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186 The Company reported that it became involved with GE during the period of 1988-1989, and that Ge had identified potential cogeneration sites internally during 1986-1987 (Tr. 1, at 51). The Company indicated that of the three priority sites, GE was willing to provide Altresco with the opportunity to work with its facilities in Pittsfield and Lynn (Exh. AL-S-17). Altresco did not include GE Selkirk in the review, as another development entity, J. Makowski, has development rights for that facility (Exh. HO-S-18S).

187 Altresco provided the following information indicating why the competing steam hosts were rejected, based on the steam host criteria: (1) GE Pittsfield was developed by Altresco; (2) GE Schnectady was slated to be studied for a paper recycling/energy production alternative; (3) GE Evandale had low steam requirements and very low electricity avoided costs; (4) GE Fitchburg had space limitations; (5) GE Syracuse had low steam requirements; (6) The Becket Paper site could not have gas delivered in a financially viable manner; (7) Revere Brass did not have sufficient long-term steam demand thereby potentially disqualifying Altresco as a QF; (8) Brandeis University was unattractive due to the complexity of the business arrangements that would be involved with the university; and (9) Bristol Myers was viewed as an alternative site for the GE Syracuse project and was rejected when the GE Syracuse site was abandoned as a viable alternative (Exhs. HO-S-2S; HO-S-18S).

of the GE River Works plant due to steam line limitations (Exh. HO-S-11).[188] Altresco and GE River Works identified three locations under control of GE in the vicinity -- the proposed site location, GE Saugus and GE West Lynn, and referred to these sites as the on-site alternatives (Exh. AL-2, at 12-11). In addition, the realty firm identified six sites, referred to as the off-site alternatives, consisting of: (1) Bennett Street in Lynn; (2) Alley Street in Lynn; (3) Rowe Contracting Company in Revere; (4 and 5) two Main Street sites in Saugus; and (6) Broadway Nursery in Lynnfield (id. at 12-9, 12-10).

The Company stated that it did not meet with City of Lynn officials to discuss and identify possible sites for the project (Exh. HO-S-8). Altresco also stated that the Company's early contact with the City of Lynn took the form of exploring the acceptability of building a cogeneration project in the city via an introduction by GE River Works personnel (Exh. HO-RR-56; Tr. 7, at 105). Altresco noted that it did not conduct a similar meeting with the City of Revere or the Town of Saugus, and in fact, did not meet with either community in any capacity until after the July 1991 public hearings (Exh. HO-RR-56).

Altresco applied the ten site-specific criteria to each of the nine sites in a matrix format, utilizing the scoring system described in Section III.C.1, above (Exh. AL-3, Table 12-1). The Company asserted that none of the alternative sites was clearly superior to the proposed site. Further, the company stated that the proposed site scored higher in both environmental and business sensitivities than all other sites considered (id. at Tables 12-2, 12-3; Exh. AL-2, at 12-11;).

b. Analysis

In regard to the selection of a steam host, the Siting Board notes that, although the Company subjected all of the identified sites to a review based on the six steam host criteria, comprehensive documentation of the application of all of the criteria was provided only for GE River Works. Altresco indicated that the alternative sites were rejected based on one or

188 Altresco stated that it selected five miles as a reasonable distance considering line losses of energy in steam between the steam host and the steam source, and the ability for the facility to operate economically (Company Initial Brief at 113).

more fatal flaws with each site. In addition, the time frame for review suggests that Altresco was focused on pursuing a continuing relationship with GE, and based on the three priority GE sites, had decided early in the selection process that GE Lynn was the next development opportunity after the Company completed Altresco Pittsfield. The Siting Board recognizes that it may be quite reasonable for a utility or non-utility generator to have an on-going site selection process where more than one facility is planned. In a prior utility review where such a siting process occurred, however, the Siting Board noted that it expects companies to review the continued appropriateness of site selection criteria, weighting, scoring and ranking developed in studies that are prepared several years prior to the filing of the company's petition. 1993 BECo Decision, at 53. This applies equally to non-utility proponents. Here, the overall timeframe was such that the Siting Board is confident that the Company did not overlook or eliminate any alternative as a direct result of the process. However, the Siting Board cautions future applicants that, where a site selection process for one project is incorporated within a larger, ongoing site selection process for multiple projects, applicants will have to show means used to keep data and criteria current.

In regard to Altresco's application of its criteria for the identification and evaluation of specific sites in the vicinity of GE River Works, the record shows that the sites were subjected to a comprehensive evaluation and scoring system. However, the Siting Board notes that the identification of sites, while addressed by the local realty firm, could have benefited from input from the surrounding communities and public participation in the process. Further, the Siting Board notes that Altresco relied heavily on GE for community relations outreach, insulating themselves from the host and surrounding communities until after the noticed public hearing. In the past, project proponents have been encouraged to include community input into their site selection process. 1993 BECo Decision at 52; 1992 Berkshire Decision, 25 DOMSC at 61; 1990 Berkshire Decision (Phase II), 20 DOMSC at 163. The Siting Board strongly reiterates its recommendation that in the future Altresco and other petitioners should include the local community and government in an open, participatory process from the inception of the project.

Nevertheless, based on the foregoing, the Siting Board finds that Altresco has appropriately applied its criteria for identifying and evaluating alternatives sites in a manner that ensures that it has not overlooked or eliminated any clearly superior sites.

4. Geographic Diversity

Altresco asserted that the selection of the proposed site meets the standard set forth in MASSPOWER, and, therefore, Altresco is not required to include a noticed alternative site for the proposed facility (Exh. AL-2, at 12-2; Company Initial Brief at 104-105). Altresco stated that it has established that (1) GE River Works has executed a steam sales agreement with Altresco that is sufficient for the proposed project to qualify for QF status, and (2) GE River Works has executed a site lease agreement with Altresco to allow the facility to be fully located within GE's property boundaries (Exh. AL-2, at 12-2; Company Initial Brief at 104). Accordingly, consistent with MASSPOWER, the Siting Board finds that Altresco is not required to provide a noticed alternative site with some measure of geographic diversity.

The Siting Board also acknowledges, as Altresco has noted, that the proposed site is located within the Coastal Zone Management area as defined pursuant to 980 CMR 9.00 (Exh. AL-2, at 12-8). The Company noted that CZM Policy 8 states that if a steam host for a cogeneration project is located in a coastal zone, the applicant must evaluate a noticed alternative located outside of the coastal zone (id.). However, Altresco indicated that the GE West Lynn site, which was located outside of the coastal zone, was deemed to be unavailable for development and was withdrawn as the noticed alternative after the 1989 original filing (id.; Exh. HO-S-6). The Company indicated that during the site review process GE entered into advanced negotiations for the sale of the GE West Lynn site for commercial development (Exh. HO-S-6). Altresco cited correspondence from CZM to the Siting Council indicating that, as the Company had acted in good faith in attempting to comply with CZM

Policy 8, and thereby had proceeded in a manner consistent with CZM Policy 8, an additional noticed alternative was not required (Exh. HO-S-7).[189]

As set forth in Section III.B.1 above, when a proposed site is located in the coastal zone as defined under the CZM regulations, the project proponent must evaluate at least one inland alternative site. 980 CMR 9.02(1)(a). Here, Altresco acted in accordance with the intent of CZM Policy 8 and, following a good faith effort to comply with the policy was allowed to proceed with the project formally, in the absence of a second noticed alternative.[190] Further, the project is a cogeneration project, specifically tied to the location of its steam host, consistent with the standard set forth in MASSPOWER. As described in Section III.B.2 and III.B.3, above, the Siting Board has found that Altresco has developed and appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures it has not overlooked or eliminated any clearly superior sites, which specifically addresses the selection of a steam host. Therefore, the Siting Board finds that Altresco has complied with CZM Policy 8 as embodied in 980 CMR 9.00 et seq in regard to its site evaluation. As noted above in Section III.B.3, all of the alternative steam host sites considered by the Company were rejected based on one or more fatal flaws regarding each site. For this reason and the other reasons stated above, the Siting Board also finds that Altresco has complied with the CZM requirement that its site evaluation and comparison "include a justification of the necessity for or advantage of coastal siting" for its proposed facility. 980 CMR 9.02(1)(a).

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189 In the letter from CZM to the Siting Council, CZM's director stated: "[i]n general, if an applicant proposes an inland alternative which is subsequently found to be unavailable, and the loss of the alternative is clearly due to factors beyond the control of the applicant, then we believe that the applicant has proceeded in a manner consistent with CZM Policy 8" (Exh. HO-S-7).

190 The Siting Board notes that the Company considered an array of alternative sites which were reviewed in the site selection process, and that the Siting Board found that the Company had not overlooked or eliminated any clearly superior sites.

5. Conclusions on the Site Selection Process

The Siting Board has found that: (1) Altresco has developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) Altresco has appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures that it has not overlooked or eliminated any clearly superior sites; and (3) Altresco is not required to provide an alternative site with some measure of geographic diversity.

Further, the Siting Board has found that Altresco has complied with the CZM requirement that its site evaluation and comparison "include a justification of the necessity for or advantage of coastal siting" for its proposed facility.

Accordingly, the Siting Board finds that Altresco has considered a reasonable range of practical facility siting alternatives.

C. Environmental Impacts, Cost and Reliability of the Proposed Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to 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. 1993 BECo Decision at 29-30; 1991 Berkshire Decision, 23 DOMSC at 324. In cases where noticed alternative(s) are not required, the facility proponent still must demonstrate that the proposed site for the facility will minimize environmental impacts and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability. 1993 BECo Decision at 32; EEC, 22 DOMSC at 315-316; MASSPOWER, 20 DOMSC at 383-404.

An overall assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. 1993 BECo Decision at 30; Enron, 23 DOMSC at 137. A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. 1993 BECo Decision, at 31; Enron, 23 DOMSC at 137.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. 1993 BECo Decision at 31; EEC, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in respective facility proposals. 1993 BECo Decision at 31; EEC, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular decision must be clearly described and consistently reviewed from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[191] 1993 BECo

191 The Siting Board notes that project proponents are required to submit to the Siting Board a substantially accurate and complete description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of a generating facility provide a description of the primary and alternative sites and the surrounding areas in terms of: natural features, including, (continued...)

Decision, at 31-32. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Id., at 32.

Accordingly, in the sections below, the Siting Board examines the environmental and cost impacts of the proposed facilities at the Company's proposed site to determine: (1) whether environmental impacts would be minimized at the site and (2) whether an appropriate balance would be achieved at the site among conflicting environmental concerns as well as among environmental impacts, cost and reliability.

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[191](...continued)

among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impact of the facility in terms of its effect on: the natural features described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 CMR 7.04(8)(e).

In cases where a site is proposed in the coastal zone, as defined by CZM statutes and regulations, the Siting Board's Coastal Zone Facility Site Selection, Evaluation and Assessment Regulations require: (1) an environmental description of each site and its vicinity, including a review of: significant land, air, and water use; ecology; geology; hydrology; meteorology; (2) an environmental analysis of construction impacts; (3) an environmental analysis of facility operation, including, but not limited to, land, air and water use impact, waste impacts, visual and aesthetic impacts; (4) a socioeconomic impact analysis, including measures to mitigate adverse impact during construction and operation; and (5) an analysis of all measures taken to comply with land, air, and water use and ecological standards, policies, regulations, bylaws and statutes of the Commonwealth and its political subdivisions. 980 CMR 9.02(1)(b).

Finally, the Siting Board notes that G. L. c. 164, § 69J also requires that plans for construction of new facilities be consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth.

2. Environmental Impacts of the Proposed Facilities

2. Air Quality

Altresco asserted that the proposed project would not cause significant deterioration to local and regional ambient air quality (Exh. HO-E-1, at 5-1). The Company stated that the stack emissions from the facility have been adequately minimized and would have acceptable impacts on air quality (Company Initial Brief at 119). Further, the Company reported that the use of natural gas minimizes the amount of SO_2 generated since natural gas has the lowest sulfur content of fossil fuels available for power generation (Exh. HO-E-1, at 6-1).

The Company indicated that emissions from the proposed facility would be controlled through the use of clean fuels, advanced control technology and advanced combustion practices (id. at 5-1). Altresco stated that emissions would be controlled to the emission rates representative of BACT (Exh. HO-E-4, at 1-1).[192] Altresco asserted that its controls would result in emission rates lower than all recently permitted combined-cycle facilities in the Northeast (id. at 6-1).

The Company's witness, Mr. Lipka, further asserted that actual operating conditions would likely result in emissions that are lower than the emissions stated in the air permit as the amount of back-up oil burned would probably be less than the five days allowed under the air permit application, and that the equipment would outperform the stated guarantees as manufacturers are often conservative in their estimates (Exh. AL-8, at 5; Tr. 6, at 21).

(1) Applicable Regulations

Altresco stated that NOx and SO_2 emissions from gas turbine facilities are regulated by the EPA's New Source Performance Standards ("NSPS") (Exh. HO-E-4, at 3-1). Further, the NAAQS limit the total allowable ambient levels of six pollutants, referred to as

[192] The Company stated that BACT is defined as an emission limitation based on the maximum degree of reduction of any regulated pollutant which DEP, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available controls (Exh. HO-E-4, at 4-1).

criteria pollutants: (1) SO_2; (2) PM-10;[193] (3) NOx; (4) CO; (5) O_3;[194] and (6) lead (id. at 3-2). All geographic areas are classified as attainment, non-attainment, or unclassified on a pollutant-by-pollutant basis in compliance with NAAQS (id. at 3-3). The City of Lynn is non-attainment for ozone and TSP, and unclassified for PM-10 and carbon monoxide (id.).[195]

In addition to the above required standards, the Prevention of Significant Deterioration ("PSD") program applies to major new sources and establishes additional air quality related criteria for attainment areas (id. at 3-3). However, Altresco asserted that the proposed facility is not subject to PSD new source review for NOx, SO_2, PM-10, CO or any other pollutant regulated under the Clean Air Act because potential emissions of each such pollutant are less than 250 tons per year ("tpy") (id. Table 2-1; Exh. HO-E-1, Table 5.1-1). Finally, the non-attainment new source review applies to the emissions for each pollutant designated non-attainment for Lynn (Exh. HO-E-1, at 5-4). However, Altresco stated that, the facility is not subject to non-attainment review for TSP and VOC because potential emissions are less than 100 tons per year for each such non-attainment pollutant (id.).

(2) Predicted Impacts

Altresco predicted the emissions of pollutants and ambient air quality impacts of such emissions, and conducted an analysis of potential fogging/icing impacts that would be produced by the project (id. at 5-10; Exh. HO-E-4, at 5-7, Table 2-1). The Company noted that its ambient air quality analyses are based on burning gas 360 days per year and using oil

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193 Altresco stated that PM-10 standards replace the standards limiting ambient levels of total suspended particulates ("TSP"); the DEP has adopted the same ambient air quality standards and is in the process of replacing its TSP standard with the federal PM-10 standard (Exh. HO-E-4, at 3-2).

194 Since O_3 is a secondary pollutant, volatile organic compounds ("VOC") are regulated as a precursor of ozone (Exhs. HO-E-4, at 3-4; AL-8, at 6).

195 All of Massachusetts is non-attainment for ozone (Exh. AL-8, at 6). All unclassified areas are regulated as attainment areas (id.).

the remainder of the year, which is the proposed upper limit on the air quality permit (Exh. HO-E-4, at 1-1; Tr. 6, at 22).[196] In addition, the annual emissions are based on the proposed facility operating at full load-firing rates, 24 hours a day, seven days a week, which Altresco maintains is a worst case scenario (Exh. HO-E-4, at 2-4).

The Company reported that the NOx emissions from the facility during natural gas firing would be reduced to 6 parts per million by volume ("ppmv") (corrected to 15 percent oxygen) and 14 ppmv when burning oil (id.; Exh. HO-E-1, at 2-3, 5-2).[197] Altresco stated that NOx would be controlled through the use of advanced dry low-NOx combustor technology and SCR (Exh. HO-E-1, at 5-1). Altresco indicated that its proposed emission levels are well below the NSPS standard of 75 ppmv (Exh. HO-E-4, at 3-1). Altresco

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196 The Company indicated that the backup fuel it will burn is very low sulfur distillate oil, which would contain at most 0.05% sulfur, compared to 0.2-0.3% sulfur in ordinary No. 2 distillate oil (Exh. AL-8, at 6).

197 During testimony on the likelihood of Altresco being required to comply with NOx Lowest Achievable Emissions Reduction ("LAER") parameters of the Clean Air Act Amendments of 1990, the Company asserted that it has performed a "top down" BACT analysis as noted in its Major Comprehensive Air Plan Approval Application (Exh. HO-RR-21; Tr. 3, at 86-88). Regarding limits for NOx stack concentration, the Company stated that 6 ppm for gas firing and 14 ppm for oil firing are representative of "top" technology under the "top down" BACT methodology (id.). Altresco also stated that its review of EPA's BACT/LAER Clearinghouse Information System and data from the California Air Pollution Control Officers Association indicates that the most recent BACT/LAER levels range from 3.5 ppm to 9 ppm (Exh. HO-RR-21).

Altresco asserted that, assuming that a reduction of NOx to 3.5 ppm at the proposed facility is considered to be LAER, such a reduction could be realized with system modifications (Exh. HO-RR-21). Altresco further asserted that technical modifications would be capable of reducing NOx emissions from 159 tons per year to less than 100 tons per year (id.). Altresco conceded that level of reduction would not enable the facility to achieve an emission rate of less than 50 tons per year, and that it thus would be necessary to purchase NOx emission offsets to meet these potential new source permitting requirements (id.).

further asserted that BACT for facilities in this size range would be 9 ppmv for gas and 18 ppmv for oil -- levels higher than its proposed emissions (Exh. HO-E-1, at 6-1).[198]

The Company indicated that the maximum sulfur content is expected to be 0.006 lbs/MMBtu for natural gas and 0.05 lbs/MMBtu for oil (Exh. HO-E-4, at 2-4 and 2-5). Altresco stated that emissions and impacts of particulates, CO, and hydrocarbons, are well within regulatory limits (Exh. HO-E-1, at 6-2). The Company further stated that CO would be controlled through the use of a catalytic oxidation system, which also serves to reduce any residual hydrocarbon emissions (id.; Exh. HO-E-4, at 2-5).

In accordance with NAAQS, Altresco used two dispersion models to determine whether any criteria pollutants -- CO, NOx, SO_2, or PM-10 concentrations -- might have predicted impacts above the significant impact levels ("SIL") (id. at 5-7; Exh. HO-E-4, at 5-1).[199] The first model, the Industrial Source Complex Short-Term ("ISCST"), is an EPA-approved computer dispersion model used to calculate ground level impacts from stack emissions (Exh. HO-E-4, at 5-1). The second model, known as the Valley model, based on an elevated terrain, uses parameters keyed to hypothetical worst case conditions (id. at 5-2).[200] Altresco reported that the results of both the ISCST model and the Valley model showed that all air quality impacts of the proposed facility would be below the SILs for all pollutants and all averaging periods (id.; Exh. HO-E-1, at 5-7, Table 5.1-3).

The Beach Association stated that the pollution generated by Altresco would coexist with the pollution being generated by GE River Works and RESCO, and noted that the Point

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198 These BACT levels are developed by the Northeast States for Coordinated Air Use Management ("NESCAUM") stationary source committee (Exh. HO-E-4, at 4-3).

199 The EPA and the DEP use SILs to determine air quality modeling requirements, specifically to establish thresholds for new source impact review and for PSD increment review (Exh. AL-2, at 13-7).

200 The hypothetical worst case condition required by the EPA and the DEP is a stable atmosphere and the persistence of the same wind direction at a wind speed of 2.5 meters per second (Exh. HO-E-1, at 5-10).

of Pines community would be affected by any new sources of air pollution (Beach Association Initial Brief at 7-8).

Altresco asserted that if the projected concentrations are below the SILs, then a detailed assessment of the background concentrations and impacts of other major sources is not generally required; therefore, interactive modeling to consider other emission sources was not conducted (Exhs. AL-2, at 13-7; HO-E-13). However, the Company provided documentation on the 24-hour SO_2 impacts from the proposed facility, whereby it determined that the predicted maximum impact is 2.5 percent of the margin remaining between background and the ambient standard (Exh. HO-RR-40).[201] Further, Altresco asserted that the facility would have the necessary emission control systems to minimize impacts to the local environment while producing economic and reliable energy (Company Reply Brief at 14).

The Company stated its study showed that icing and fogging effects from cooling tower emissions generally arise under ambient conditions associated with fog, rain, or snow events, and that, therefore, the contribution from the cooling tower is expected to be insignificant (Exh. HO-E-10). Altresco noted that its analysis included the Seasonal/Annual Cooling Tower Impact Model which predicted that there would not be any ground level fogging or icing along local public highways or nearby bridges (Exh. HO-E-1, at 5-12). The Company reported that the cooling tower plume would only impact ground level locations close to the cooling tower -- within the confines of the River Works Complex and some adjacent areas in the Saugus River - for a limited number of hours annually (Exh. HO-E-10; Tr. 6, at 33).

Finally, Altresco stated that the proposed facility would emit approximately 627,500 tons of CO_2 per year (Exh. HO-RR-44). The Company stated that it is committed to

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201 The background concentration of 160 micrograms per second ("ug/m^3") is 47% of the ambient standard of 365 ug/m^3. Further, the Siting Board notes that, for oil-fired emissions, the predicted maximum emission rate of 4.97 ug/m^3 was only slightly below the SIL emission rate of 5 ug/m^3 that triggers a comprehensive analysis and review by DEP (Exh. HO-E-4, Table 5-1).

contributing \$5,000 per year for five years to the Massachusetts ReLeaf tree-planting program ("Mass ReLeaf"), which would purchase 250 trees, based on a cost of \$100 per tree (id.; Exh. HO-E-63). Altresco calculated that the contribution to Mass ReLeaf would offset 3750 tons of CO_2 over the 20-year life of the proposed facility, or approximately 0.03 percent of its emissions (Exh. HO-RR-44).[202] However, the Company asserted that by displacing other units, Altresco would offset 150 percent of its CO_2 emissions, thereby attaining a net reduction of CO_2 (id.).[203]

(3) Analysis

Altresco has provided adequate support for its assertion that emissions of criteria pollutants from the proposed facility would not add significantly to the existing air quality pollutant concentrations. The Siting Board notes that NOx emissions would be controlled to the lowest level reviewed by the Board to date. Further, Altresco has supported its position that cooling tower vapor emissions would not significantly increase fogging or icing in the surrounding communities.

With respect to an analysis of CO_2 impacts, the Siting Council first established in Enron the requirement that all applicants of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 impacts. 23 DOMSC at 196. In the EEC Compliance Decision, the Siting Council further provided that future applicants must present alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, to demonstrate that all cost-effective approaches have been adequately considered. 25 DOMSC at 358-360.

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202 The company estimated that a planted tree would offset 30 tons of CO_2 over 40 years, and therefore assumed that each tree would offset 15 tons of CO_2 over the 20-year life of the proposed facility, which is 0.75 tpy per tree (Exh. HO-RR-44).

203 For a further discussion of the NEPOOL dispatch analysis prepared by Altresco, see Section II.A.3.f, above.

Altresco's initial filing in this proceeding predated both the above holdings concerning analytical requirements for CO_2 impacts. Thus, the analytical requirements set forth in Enron and EEC Compliance were not met by Altresco.

With respect to the level of CO_2 mitigation in Enron, the Siting Council accepted a specific CO_2 mitigation cost commitment for that project without setting forth a guideline or standard for determining the adequacy of CO_2 mitigation. 23 DOMSC at 195-196. As part of its review of the adequacy of proposed CO_2 mitigation in EEC Compliance, however, the Siting Council set forth general criteria it will consider to determine the adequacy of CO_2 mitigation in such reviews, as well as approving a particular cost commitment for that project. 25 DOMSC at 361-367. Specifically, the Siting Council stated that it may consider various relevant project factors -- for example facility cost, facility CO_2 emissions, and any increment of such emissions exceeding the emissions of displaced capacity ("net-of-displacement emissions") -- in order to determine the appropriate level of CO_2 mitigation for proposed facilities.[204] Id., 25 DOMSC at 365. The Siting Council also stated that in the future it would be preferable for applicants to address the adequacy of CO_2 mitigation in terms of the quantity of CO_2 emission offsets to be attained rather than in terms of the cost to be committed for providing CO_2 emission offsets. Id., 25 DOMSC at 362.

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204 In establishing that both total emissions and net-of-displacement emissions could be appropriate indicators, the Siting Council noted that it may not be clear as to whether a proposed facility would serve primarily to displace existing power generating facilities or to meet future load growth. EEC Compliance, 25 DOMSC at 363. The Siting Council recognized that, to determine the appropriate level of CO_2 mitigation, it is necessary to relate a proposed facility's CO_2 emissions to net changes in regional or national emissions. Id. To the extent that a proposed facility would displace existing power generating facilities, there may be a beneficial or adverse impact on regional or national levels of CO_2 emissions corresponding to the difference between such proposed facility's emissions and those of the displaced generation. Id. To the extent that a proposed facility is to be built in whole or in part to meet load growth, new generation may be added to the region's supply faster than old generation is retired or otherwise displaced. Id. In this latter situation, the net impact of a proposed facility on regional/national CO_2 emissions may not correspond to the difference between its emissions and those of any alternative energy resource, but rather may reflect more closely the total CO_2 emissions from such proposed facility. Id.

Having set forth in EEC Compliance general criteria for determining the adequacy of CO_2 mitigation, the Siting Council reviewed in that proceeding EEC's proposal to offset approximately 0.4 percent of facility CO_2 emissions through participation in the Mass Releaf program, at a cost of $1.2 million. Id., 25 DOMSC at 349-350, 365-367. The Siting Council required EEC to increase its cost commitment to $2 million, and to allocate these resources between the Mass Releaf program and a more cost-effective reforestation approach. Id., 25 DOMSC at 350-351, 366-368. While the Siting Board did not specify the precise allocation, data from EEC Compliance indicates that an equal allocation of resources between the Mass Releaf program and the reforestation approach would result in offsetting approximately 0.8 percent of EEC's facility emissions.

Here, Altresco proposes to offset approximately 0.03 percent of the proposed facility's CO_2 emissions. Thus, as in EEC Compliance, Altresco's proposed CO_2 offsets are a small fraction of expected total CO_2 emissions from the proposed facility.

The Siting Board recognizes that EEC's proposed CO_2 offsets in EEC Compliance also were a small fraction of that facility's net-of-displacement emissions, assuming the project would serve to displace existing generation. Id., 25 DOMSC at 366. In contrast, to the extent the proposed Altresco facility would serve to displace existing generation, its expected CO_2 emissions would be exceeded by those from displaced capacity, and could be as little as two-thirds of the CO_2 emissions from displaced capacity. Further, EEC's proposed offsets were partly negated by expected on-site tree clearing for that facility, while Altresco's proposed facility would not require on-site tree clearing.

Nonetheless, on a MW-for-MW basis, Altresco's total CO_2 emissions are fully half those reviewed in EEC Compliance, while its proposed CO_2 offsets are less than one-twentieth those required of EEC (and about one-thirteenth those proposed by EEC). Accordingly, the Siting Board finds that Altresco has not established that the CO_2 emissions impacts of the proposed facility would be minimized.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of Altresco's proposed BACT, and with the exception of CO_2 emissions, the environmental impacts of the proposed facility would be minimized with respect to air quality.[205]

a. Water Supply and Wastewater

Altresco stated that it proposes to use treated effluent from the LWSC municipal wastewater treatment facility ("WWTF") as a source of non-potable water for cooling tower make-up on a long-term basis, thereby conserving potable water supplies (Exhs. HO-E-1, at 5-15; AL-2, at 1-2). The Company indicated that potable water would be used only for boiler water make-up and gas turbine injection water as well as for plant sanitary purposes (Exh. HO-E-1, at 5-15; Tr. 1, at 67 and 72).

The Company asserted that there would not be any negative impact from the proposed facility's water use on the City of Lynn water supply (Exh. AL-1, at 12). Further, Altresco asserted that the use of the effluent would significantly reduce organic waste loading to Lynn Harbor (Exh. HO-E-1, at 5-17).

The Company indicated that the proposed facility would require an average of 659 gallons per minute ("gpm") and a maximum of 1,163 gpm of treated effluent, to be used for cooling water (Exh. HO-E-18). Altresco demonstrated that the proposed project would reduce LWSC's discharge to Lynn Harbor by an average of approximately 400 gpm and a maximum of 757 gpm (Exh. HO-E-1, Fig. 5.2-1).[206] Altresco noted that the reduced wastewater discharge would result in a net reduction in the discharge of organic pollutants to Lynn Harbor on the order of approximately 100 tons per year (Exh. HO-E-66).

The Company reported that the LWSC secondary effluent would be treated prior to its use as cooling tower make-up, and that the treatment is necessary to reduce the level of

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205 The Siting Board reviews whether Altresco's proposed level of CO_2 mitigation or a higher level of CO_2 mitigation would allow the Company to establish that the CO_2 emissions impact of the proposed facility would be minimized consistent with minimizing cost in Section C.4.

206 The proposed facility would intake an average of 659 gpm (1,163 gpm at peak maximum) of process water from the WWTF and return an average of 259 gpm (406 gpm at peak maximum) to the LWSC outfall pipe (Exh. HO-E-1, Fig. 5.2-1). A substantial amount would be evaporated in the cooling tower (id.).

biochemical oxygen demand, dissolved solids, and suspended solids prior to introduction into the cooling system (Exh. HO-E-20). Altresco indicated that the treatment process would include a lime softening and clarification system, and that the water also would be treated in the cooling tower with sodium hypochlorite and a non-oxidizing biocide to further inhibit biological activity (id.; Exh. AL-2, at 3-9). Altresco asserted that the lime softening and clarification system would produce a discharge effluent from the proposed facility after use which would consistently meet applicable local limitations (Exh. HO-E-1, at 5-13).

Altresco stated that potable water is to be used for the boilers and turbines since organic chemicals in treated effluent can potentially damage the equipment (Tr. 1, at 72, 74). However, Altresco's witness, Dr. Hill noted that the treated effluent is acceptable for use for the boiler and turbine injection and would have no short-term impact (id.). The Company noted that the potable water will be demineralized before being utilized for the HRSG boilers and turbines (id.).[207] The Company noted that the use of dry low-NOx combusters requires less potable water as no water injection to the turbines is needed when gas is being fired, and water injection is only necessary during periods of emergency oil firing (Exh. HO-E-19; Tr. 1, at 65).[208] The Company indicated that the potable water use requirements would vary from 185 gpm with gas firing to 362 gpm with back-up oil firing (Exh. BA-34; Tr. 1, at 90).[209]

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207 The demineralization system for the potable water involves reverse osmosis, mixed bed units, acid and caustic regeneration equipment, a neutralization tank, and controls (Exh. HO-E-1, at 5-18).

208 The Company explained that the demineralized water is needed for boiler water make-up under either fuel scenario; however, it is only utilized for turbine injection when oil is being used (Tr. 1, at 70).

209 The Company stated that facility operating staff would require approximately 1.0 gpm of potable water for consumption and sanitary facilities (Exh. HO-E-1, at 5-15).

The Company provided a letter of intent from the LWSC providing for the sale of effluent and potable water to Altresco (Exh. HO-E-17S).[210] Although the final contract between Altresco and LWSC was not provided, the Company stated that it anticipates the contract would be finalized by the end of July, 1992 (Exh. HO-E-17; Tr. 1, at 84). Dr. Hill indicated that a stipulation in the contract gives LWSC the right to interrupt the sale of potable water to Altresco with one years' notice (Tr. 1, at 77). However, Dr. Hill asserted that LWSC has more than adequate quantities to supply Altresco,[211] and further, that the proposed facility is designed to be run on effluent only, if a problem arises with providing LWSC potable water (id. at 74, 77).[212]

Altresco stated that the proposed facility would not need a separate National Pollutant Discharge Elimination System permit, as it would be tying into the existing WWTF outfall (id. at 82; Exh. HO-E-20S). The Company further reported that the EPA has accepted the proposed use of LWSC treated effluent and the return of wastewater, with the understanding that LWSC is solely responsible for the discharge from the outfall, notwithstanding any outstanding arrangements with Altresco (Exh. HO-E-20S).[213] Altresco stated that the effluent would be transported to the facility by a new 12-inch main, and the facility process wastewater returned to the WWTF outfall via a parallel return line (Exh. HO-E-1, at 5-19). The Company stated that all facility process wastewater would be monitored before it is discharged into the WWTF outfall and would be maintained in full compliance with

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210 The letter of intent, executed in October of 1989, specified the price of the effluent and potable water, in 1995 dollars, as $.53 and $1.81 per hundred cubic feet, respectively (Tr. 1, at 70).

211 Altresco indicated that according to the LWSC, its water usage in the past few years has been significantly less than its supply allocation (Exh. HO-E-65).

212 The Company indicated that although the system was designed to run on effluent only, it is more advantageous in the long term to use potable water for the boilers and turbines to prevent the possibility of organics fouling the system (Tr. 1, at 74).

213 As a condition of approval, the EPA would require that the two discharges must be processed through a final chlorination chamber at the LWSC facility (Exh. HO-E-20S).

discharge permit requirements (id. at 7-7; Exh. HO-E-23). Altresco asserted that the quality of the discharge would be equal to or better than the quality of effluent the proposed facility will be receiving from the WWTF (id.).

Altresco asserted that the use of municipal wastewater in circulating water cooling systems has a long and successful operating history (Exh. HO-E-16). The Company further stated that no adverse impacts are anticipated given the extensive additional treatment, both primary and secondary, to be undertaken at the proposed facility (Exhs. HO-E-1 at 5-15; HO-RR-5, at 2).[214] Altresco provided an analysis concluding that, based on the current literature, there does not appear to be a detectable difference in the likelihood of human infection in the area surrounding wastewater treatment plants associated with the use of municipal wastewater in water cooling systems (id. at 1).

The Company indicated that stormwater runoff would be diverted to the WWTF outfall along with the process wastewater (Exhs. HO-E-67; HO-E-1, at 2-9).[215] The stormwater would be segregated and retained, then would pass through an oil/water separator, and the residual oil would be drummed and hauled off-site for treatment and disposal in compliance with all regulatory requirements (Exh. HO-E-1, at 6-3, 7-17). Finally, wastewater sludge, in the amount of two to five tons per day, would be trucked off-site and disposed in a licensed commercial landfill (id. at 5-19).[216]

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214 The Company provided an analysis entitled "Potential for Adverse Effects Associated with the Theoretical Release of Pathogenic Microorganisms from the Cooling Tower of the Altresco Lynn Facility" (Exh. HO-RR-5). The analysis stated that, although a number of potentially pathogenic microorganisms have been identified in municipal wastewater, effective methods exist to inactivate the pathogens (id. at 5). The report concludes that Altresco would utilize these methods sequentially which greatly increases the overall effectiveness of pathogen removal (id. at 6).

215 See Section III.C.2.c for a further description of stormwater management.

216 The Company provided documentation indicating that transportation of all hazardous waste and waste oil would be undertaken by Clean Harbors, a licensed hazardous waste transporter (Exh. HO-E-55(c)).

In this proceeding, Altresco has demonstrated that its proposed use of recycled effluent for cooling water would be beneficial both in terms of the conservation of potable water and the reduced wastewater flow into Lynn Harbor. The Siting Board notes that Altresco has documented that there is an adequate supply of municipal potable water, and further, that the facility is designed to be operated solely on treated effluent which would not damage the system in the short-term, in the event of a potable water shortage. In regard to concerns relating to possible health effects from utilizing treated effluent, the Siting Board notes that the Company has presented documentation which demonstrates no direct impact on health associated with such use. The Siting Board notes that in previous facilities reviewed by the Siting Council, the Siting Council found that the operation of a cooling tower at a facility utilizing effluent, would have acceptable air quality impacts, as well as no other adverse impacts. Enron, 23 DOMSC at 199; West Lynn, 22 DOMSC at 96.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the above treatment plan, the environmental impacts of the proposed facility would be minimized with respect to water supply and wastewater discharge, including impacts on the facilities of the City of Lynn and on Lynn Harbor.

b. Wetlands and Waterways

Altresco stated that the only portion of the proposed facility within the jurisdiction of the Wetlands Protection Act is the installation of three new overhead transmission line towers (Exh. HO-E-32, at A-1). The Company stated that the towers would be located within the 100-foot buffer zone associated with the Saugus River, but that the proposed work area would not include any vegetated wetland resource areas (Exh. HO-E-31).

The Company further indicated that the proposed active facility site is more than 200 feet from the 100-year floodplain and the Rumney Marsh ACEC boundary (Exhs. HO-E-32 at A-6; HO-E-1, at 2-10).[217] Altresco asserted that the proposed work would not result in

[217] The Saugus River and its surrounding wetland resource areas were designated by the Secretary of the Executive Office of Environmental Affairs as part of the Rumney (continued...)

any adverse impacts to either the coastal bank or salt marsh resource areas, and further, that no vegetated wetland resource area or floodplain would be affected by the water supply or wastewater discharge lines, the steam line, or the natural gas supply line for the proposed facility (Exhs. HO-E-32, at B-3; HO-E-31). Further, the Company indicated that the proposed project would not have any adverse effect on the fisheries resources of the Pines or Saugus Rivers since construction would take place in previously developed areas (Tr. 5, at 56). Finally, the Company stated that all construction would abide by the Order of Conditions issued by the Lynn Conservation Commission (Exh. HO-E-32, at A-9).[218]

The Company indicated that while the facility site is outside of the Rumney Marsh ACEC, the footings for one of the three above-ground transmission towers would be located just within the Rumney Marsh ACEC boundary (Exh. HO-E-34). Altresco described the footing location as previously developed GE land in the vicinity of the existing GE Switchyard near the General Edwards Bridge (Exh. HO-E-1, at 5-45). The Company further reported that this portion of the Rumney Marsh ACEC does not include saltmarsh, estuary, tidal flats, or other unique resources that are important components of the Rumney ACEC designation (id. at 2-11, 5-45). Altresco concluded that the proposed work would be consistent with the existing use patterns and would not result in an increased area of impact to the Rumney Marsh ACEC (Exh. HO-E-32, at B-1).[219]

The Company stated that two of the proposed towers are located in the 100-year floodplain, which is defined as land subject to coastal storm flowage (Exh. HO-E-31). Altresco indicated that the construction of the footings would involve the temporary

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[217](...continued)
Marsh Area of Critical Environmental Concern in August 1988 (Exh. HO-E-32, at A-6).

[218] The Order of Conditions, based on the Notice of Intent, was issued by the Lynn Conservation Commission on March 26, 1992 (Exh. HO-RR-12).

[219] The Company presented correspondence from the CZM regarding the Massachusetts Environmental Policy Act ("MEPA") review, stating that the CZM does not believe that the proposed footings from the transmission tower would present any problem to the Rumney Marsh ACEC since the location is already developed (Exh. HO-E-1S).

disturbance of approximately 96 square yards of land, and the permanent loss of two cubic yards of land, thereby only minimally decreasing flood storage capacity and not interfering with storm damage protection (id.; Exh. HO-E-32, at B-1). The Company further indicated that the towers would be designed to withstand 100-year flooding (Exh. HO-E-32, at part IV). In terms of minimizing the chance of flood hazards to the proposed facility, the Company stated it would elevate equipment subject to water damage a minimum of 1.5 feet off the floor, thereby ensuring all such equipment would be above the Standard Project Noreaster flood levels (Exh. HO-E-1, at 6-5).[220]

Altresco stated that the stormwater at the proposed site would consist primarily of runoff from uncontaminated paved yard areas (id. at 6-6). The Company indicated that all stormwater emanating from the areas that Altresco utilizes would be diverted to the LWSC outfall that flows into the Lynn Harbor (see Section III.C.2.b, above) and that only the stormwater from the roof of Building 64 would continue to be managed by GE (Tr. 1, at 88).[221] Altresco estimated that five million gallons per year of stormwater would be diverted to the LWSC outfall, water that has previously flowed into the Saugus River (id. at 86; Exh. HO-E-31, at 5-56). The Company asserted that the diversion of stormwater would reduce stormwater flows to the Rumney Marsh ACEC, providing a benefit to fisheries and aquatic resources (Exhs. HO-E-1, at 6-6; HO-E-31, at 5-56).

The Siting Board notes that the active facility site will not be located in water resource or wetland areas, including the Rumney Marsh ACEC, and the 100-year flood zone. The construction of transmission tower footings in the Rumney Marsh ACEC will be confined to already developed areas directly inside the GE boundary. Further, construction of the two transmission tower footings within the 100-foot buffer zone will be subject to the stringent mitigation methods outlined in the Notice of Intent and the Order of Conditions of the Lynn

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[220] Altresco indicated that according to GE personnel, over the last 50 years, there has been no significant damage to any GE River Works property stemming from a flooding event (Exh. HO-E-90).

[221] GE currently diverts its stormwater directly into the Saugus River via a recently upgraded system (Tr. 1, at 88).

Conservation Commission. Additionally, the stormwater management plan will reduce stormwater flows to the Pines and Saugus Rivers by diverting the runoff to the LWSC outflow.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the above planned mitigation measures, the environmental impacts of the proposed facility would be minimized with respect to wetlands and water resources.

c. Noise

Altresco asserted that operation of the proposed facility would comply with DEP requirements limiting noise increases above the baseline to ten decibels ("dBA") and restricting pure tone increases (Exhs. HO-E-1, at 5-27; HO-E-4, at 6-6).[222] Further, the Company indicated that its noise analysis is conservative, and that even under these assumptions, the proposed facility would produce no increase in ambient noise at any of the selected residential locations (Tr. 5, at 8).[223]

In support of the above assertions, Altresco provided an analysis of ambient background noise levels, and expected noise increases resulting from the construction and operation of the proposed project (Exh. HO-E-45). The Company stated that it conducted ambient noise level measurements to reflect weekday and weekend, as well as daytime and nighttime conditions (Exh. HO-E-4, at E-1).[224] Altresco selected six locations for ambient

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222 The DEP has established that a new source of noise should not increase the minimum ambient sound level more than 10 dBA (Exh. HO-E-4, at 3-7). Altresco stated that it has committed to the City of Lynn Planning Board that the proposed project would comply with the DEP Noise Policy (Exh. HO-E-49).

223 Mr. Keast asserted that he selected the ambient measurement locations to reflect quiet locations in order to be conservative in his assumptions (Tr. 5, at 8).

224 The Company reported that ambient noise measurements were conducted in March of 1989 (Exh. HO-E-41). The Company asserted that ambient noise levels are generally lowest during the coldest months of the year (Exh. HO-E-77). Altresco further noted that the purpose of measuring ambient noise is to approximate the lowest existing noise level and not to describe seasonal variations (id.).

noise measurement, but analyzed noise impacts for eight receptor locations, including four residential receptors and four property line receptors (Exh. HO-E-41, Table E-41-1).[225] Altresco indicated that the residential receptor distances range from 1,850 feet to 3,900 feet from the proposed facility, and that the closest property line receptor is the south property line, located along the Saugus River (Exhs. HO-E-1, at 5-25; HO-E-4, at 6-4). Further, the Company asserted that there are no sensitive receptors, such as schools, hospitals or nursing homes, located within the 4,000 foot radius of the noise analysis (Exh. HO-E-44).

The Company stated that in order to assess the worst case effect of the operation of the proposed facility it was important (1) to establish ambient noise levels representative of quiet community areas, and (2) to predict facility noise levels in the parts of the community that would be exposed to the most noise from the facility (Exh. HO-E-44).[226] Altresco's analysis shows that the maximum noise increases resulting from operation of the proposed facility at the residential receptors is zero dBA and the maximum increase at the property lines is eight dBA at the south property line (Exh. HO-E-41, Table E-41-1).

Altresco indicated that, in general, the industrial nature of the study area combined with the proximity of heavily travelled roadways generated fairly high ambient noise levels, between the mid 40's to the upper 50's dBA (Exhs. HO-E-5; AL-2, at 13-12). The

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225 The Company conducted ambient noise measurements at six locations, of which five were residential and one was a property line (Exh. HO-E-41). The impact modeling originally was undertaken in June 1989 utilizing 12 receptors (id.). However, due to the downsizing of the facility, new modeling was undertaken in January 1992 utilizing eight receptors (id.). The Company provided a conversion table describing the relationship between the six ambient measurement sites and the final eight modeled receptors, whereby more than one modeled receptor was based on the same ambient measurement (id.). The analysis presented in the Final Environmental Impact Report ("FEIR") and the Air Plans Application is based on the final modeling and potential increases at the eight receptors (Exh. HO-RR-31).

226 The Company stated that the major external noise sources at the facility would be the intakes and exhausts for the combustion turbines, power transformers and a cooling tower (Exh. HO-E-1, at 5-21). Further, major internal noise sources would include three combustion turbine-generator sets, a steam turbine-generator and ancillary equipment (id.).

Company further noted that the noise from the existing GE River Works operations and local traffic tends to dominate the ambient noise levels throughout the area surrounding the GE complex (Exh. HO-E-6). Altresco stated that the noise produced by the proposed facility would be constant during normal operation, as the facility would operate continuously, 24 hours a day, seven days a week (Exh. HO-E-46).[227]

Altresco asserted that the noise impacts associated with the construction of the proposed facility would be slight (Exh. HO-E-45).[228] The Company indicated that based on the EPA model,[229] the noise increases at the residential receptors would be 10 dBA or less, with the exception of the noise impacts from pile driving (id.).[230] Mr. Keast asserted that construction noise would not pose a nuisance to residents since the equivalent level due to construction noise would be less than the existing daytime noise level (Tr. 5, at 30).

Altresco stated that the proposed project would incorporate noise mitigation through the use of the following equipment and design features: (1) enclosure of major mechanical equipment including the HRSGs in the power generation building; (2) enclosure of each of the three gas turbines inside interior housings in the turbine building; (3) baffle inlet silencers

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227 Altresco stated that the GE facility runs 24 hours a day, seven days a week (Exh. HO-E-47).

228 Altresco indicated that the typical hours of construction would be between 7:30 a.m. to 4:00 p.m., and that Altresco would avoid overtime and weekend construction activity whenever possible (Exh. HO-E-82).

229 The Company stated the construction impacts are based on a model published by the EPA entitled "Noise from Construction Equipment and Operation, Building Equipment, and Home Appliances", which predicts equivalent level (L_{eq}) construction noise levels based upon typical construction practices in the United States (Exh. HO-E-45).

230 Altresco stated that there are no state or federal guidelines that provide limits for construction noise, therefore the DEP noise policy is not applied to noise sources such as construction or transportation (Exh. HO-E-80).

on each inlet duct to reduce gas turbine noise;[231] and (4) placement of the major plant buildings and equipment to provide effective noise barriers between the noisier plant components and nearby land uses (Exh. HO-E-1, at 6-4).

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental requirements, including the DEP's ten-decibel guideline. Boston Edison Company (Phase II) at 104; Enron, 22 DOMSC at 210; Altresco-Pittsfield, 17 DOMSC at 401. In addition, the Siting Board 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. Boston Edison Company (Phase II) at 104; Enron, 23 DOMSC at 210-211; NEA, 16 DOMSC at 402-403.

Here, the operation of the proposed facility would result in residential receptor noise increases that are not only within the DEP ten decibel guideline, but do not increase the existing noise level to any registered degree. Further, the noise increases at the property lines are within the DEP guidelines, with the largest increase occurring at the Saugus River shoreline.

As in Enron, the ambient residential noise levels are among the highest addressed by the Siting Board in reviews of proposed generating facilities. 23 DOMSC at 210-211. However, in Enron, the noise levels reflected a combination of the background noise and an actual facility noise increase in measured dBA. Id. In this case, the Altresco facility is not contributing to any measurable increase in the existing residential ambient noise levels due to the operation of the plant. In addition, although expected noise increases during maximum construction activity would be higher than during operation of the proposed facility, the noise impacts would be of limited duration and would be confined to daytime hours.

231 Altresco stated that the O&M contractor would be responsible for noise monitoring and ensuring that the silencers are kept in working order (Exh. HO-RR-55).

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the above mitigation, the environmental impacts of the proposed facility would be minimized with respect to noise impacts.

The Siting Board notes that project configurations are subject to change during the filing process, especially for projects that choose to file updates or supplemental evidence. However, recognition of how the changes will affect specific analyses should be addressed by the petitioner. In this case, the use of different ambient and modeled receptors, and variations on receptor identification added unnecessary confusion. In the future, petitioners should anticipate the need for several property line and residential receptors at the beginning of the process to ensure a clear, comprehensive noise analysis.

d. Land Use

Altresco asserted that since the proposed site is currently being used for industrial purposes, there would be no change in current land use patterns (Exh. AL-2, at 1). The Company further stated that the proposed facility is completely consistent with the existing industrial characteristics of the GE River Works complex (Company Initial Brief 22 at 172).

The Company stated that the project site is developed industrial land with no special ecological significance (Exh. AL-2, at 13-21). Altresco reported that according to the Massachusetts Natural Heritage and Endangered Species Program, there are no rare or endangered species or plants that would be affected by the project (Exh. HO-E-30A). Altresco further indicated that although the project site is located in a Coastal Zone, it has been used as an industrial site for many decades and would not be significantly altered from its present condition by the operation of, or as the host of, a cogeneration plant (Exh. AL-2, at 12-14).

The Company reported that the proposed site is bounded by residential areas to the north and northwest, by Route 1A (the Lynnway) to the east, by Route 107 (Western Avenue) to the west, and the Saugus River and a marsh area to the south (id. at 13-9). Further, a MBTA commuter rail line runs through the eastern portion of the site (id.).

Altresco stated that the 5.7-acre active site, located within the 223-acre GE River Works Complex, features very favorable site buffer characteristics with respect to surrounding land uses (id. at 12-11; Exh. HO-E-1, at 2-1). The Company reported that the majority of the industrial property west of the Lynnway is owned by GE, and noted that other industrial uses are in close proximity to the site, including a MBTA yard and the Stone Packaging Corporation located next to GE on the east, a MBTA bus repair and storage yard to the west, and the RESCO facility located across the Saugus River (Tr. 1, at 90).

Altresco stated that the nearest residential location is 1,850 feet northeast of the project site, at the end of Varnum Street in Lynn (Exh. HO-E-4, at 6-4). Mr. Hill categorized the residential neighborhoods surrounding the facility in Lynn, Revere and Saugus as medium density, based on observations of existing single and multi-family development (Tr. 1, at 91). The Company indicated that the residences located within a half-mile radius of the proposed site are confined to Lynn (Exh. HO-E-70). Further, the Company indicated that there are approximately 275 residences located within a half mile radius, while within a one-mile radius there are 2,300 residences located in Lynn, 525 residences located in Revere, and 350 residences located in Saugus (id.).

Altresco stated that the project is located in an area zoned for heavy industry, but that a special permit was needed for the type of facility, building height, stack height and transmission towers (Exh. HO-E-71).[232] A Special Permit was issued by the City of Lynn on November 12, 1991, wherein the City stated that the height of the proposed facilities was consistent with the character of adjacent properties in the GE industrial complex, and noted that the site surrounding the project contains an existing heavy industrial manufacturing

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232 The Special Permit was required to: (1) permit the use of the property as a manufacturing facility for steam and electric power cogeneration; (2) permit the use of buildingthe property for a fuel storage facility; and, (3) permit construction of a with a maximum height of 82.5 feet and the construction of transmission towers and exhaust stacks with a maximum height of 213 feet (Exh. HO-B-9, at 1). The Company stated that the maximum building height normally allowed under the City of Lynn zoning by-laws is 60 feet (Exh. HO-B-12). The Company noted that existing structures on the GE site are up to 190 feet high (see Section III.C.2.f, for a description of visual impacts of proposed facility) (Exh. AL-2, at 13-24).

facility and has for over 100 years (Exh. HO-B-9, at 4). The residential areas to the north and northwest of the facility are zoned "R4", a residential district designated "Apartment House District, Class 2" (Exh. HO-E-25).[233]

Altresco asserted that the GE River Works complex is a water-dependent industrial use according to Waterways regulations promulgated under G.L. c. 91, located in part, on filled tidelands (see 310 CMR 9.12(C)(1)) (Exh. HO-E-33, at A-7 and A-11). The Company indicated that the regulatory provisions of Chapter 91 give licensing preference to water-dependent projects in tidelands (id.).[234] Altresco provided correspondence from the Massachusetts Division of Wetlands and Waterways indicating that the division has determined that the proposed use of filled tidelands for a cogeneration facility that is accessory to the GE River Works is a water-dependent use (Exh. HO-E-1S).

The Company stated that a large portion of the 2.5-mile gas pipeline to be constructed by Tennessee is proposed to travel through an existing MBTA-owned ROW (see Section II.C.3.b., above) that has been used for public purposes for many years (Tr. 7, at 20). Altresco asserted that utilizing this route would have the lowest environmental impact of other options that it examined,[235] as it predominantly involves previously disturbed land, and that the construction outside of the ROW would be confined to a short distance connecting the existing meter station (Lynn Homesite) with the ROW (id.).

The Siting Board finds that the proposed facility would be compatible with the surrounding industrial nature of the GE complex and that a significant buffer exists between

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233 The City of Lynn has five residential zoning categories, of which R4 corresponds to the fourth highest density (Exh. HO-E-25).

234 Altresco stated that the primary purpose of G.L. Chapter 91 and its regulations is to preserve, protect, and enhance public trust rights in tidelands, great ponds, rivers and streams of the Commonwealth (Exh. HO-E-1, at 5-42).

235 The Company's witness, Mr. Corbett stated that Altresco has supplied this plan to assure itself that there is an environmentally viable route to transport the gas to the proposed facility, however, he noted that the actual routing would be proposed by Tennessee to the FERC, and it is the FERC who would make the determination as to the final route (Tr. 7, at 23).

the proposed facility and non-industrial, developed land. The facility is also compatible with the industrialized land uses abutting the complex. Further, the proposed facility would be located in a heavy industrial zone, and has been granted a Special Permit by the City of Lynn.[236]

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to land use.

e. Visual Impacts

Altresco stated that the most prominent visual feature of the proposed facility would be the three exhaust stacks (Exh. AL-2, at 13-22). The Company asserted that the stacks would be consistent with the existing visual elements of the area, and further would be compatible with the intensive industrial character of the surrounding area (id. at 13-25; Exh. HO-E-1, at 5-32). Altresco indicated that the dimensions of the three stacks would be between 199-200 feet in height, have an inside diameter of 12 feet, and would be located approximately 60 feet apart (Exhs. HO-E-35; HO-E-36S).[237] The Company stated that each stack would be equipped with the required sampling and access platform, to be located 25-30 feet below the top of each stack (Exhs. AL-2, at 13-22; HO-E-74).[238]

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236 The Siting Board notes that the issuance of a Special Permit by a local entity, while important to the overall permitting process, does not in and of itself determine Siting Board acceptance of the site under land use impacts. The Siting Board conducts an independent review of items such as zoning, site compatibility, and surrounding land use.

237 The record indicates that the Company asserted in the City of Lynn Special Permit and Altresco application to the Siting Council that the height of the proposed stacks would not exceed 213 feet (Exhs. HO-E-71; AL-2, at 13-22). However, during the proceedings, the Company submitted information detailing that the stacks would be between 199-200 feet high (Exh. HO-E-36S). The Company stated that the inside diameter would be determined by the boiler manufacturer (Exh. HO-E-35; Company Initial Brief at 165).

238 The Company stated that the stacks would not be equipped with warning lights, as they fall below the 200 foot threshold for the mandated installation of warning lights (Exh. HO-E-35).

Altresco asserted that the proposed facility is located within an industrial complex, and, therefore, other industrial buildings, stacks and structures would screen views of the facility (Exh. HO-E-37). The Company stated that a sizable buffer, consisting of at least 1,500 feet in width, exists between the proposed facility and other developed land not associated with the GE River Works complex (Exh. HO-E-1, at 5-42). The Company indicated that the proposed Altresco HRSG building would be located to the east of GE Building 64, and would be 79-80 feet in height (Exh. HO-E-36S). Altresco stated that the proposed facility is to be located to the south and east of the existing GE River Works Power House which is 86 feet high (Exhs. AL-1, at 13; AL-2, at 13-24). Further, the Company reported that the GE site presently has six exhaust stacks associated with the power house, ranging in height from 103 feet to 190 feet (Exh. AL-2, at 13-24).

The Company further asserted that the project area itself is industrialized in nature and pointed to the RESCO facility located across the Saugus River as an example of nearby heavy industry (id. at 13-25). Altresco reported that RESCO has recently constructed a new 286-foot high exhaust stack, with an overall outside diameter of 30 feet and noted that the height of the RESCO facility building is 114 feet (id. at 13-24). The Company stated that the upper portion of the Altresco stacks would be visible from certain neighborhoods, however Altresco noted these same neighborhoods currently have views of the existing GE stacks as well as the RESCO stack (id. at 13-25; Exh. HO-E-1, at 5-31).

The Company stated that it conducted a visual survey of the project area to determine the locations of concern regarding visual impacts of the facility (Exh. AL-2, at 13-24). Altresco prepared representations of views from four visual receptors, two in Lynn and one each in Saugus and Revere (Exh. HO-E-1, Figure 5.5-1). Altresco stated that it presented enlarged photographs with overviews of the proposed facility from the receptors at six public meetings held by the Company, and further asserted that there were no objections raised at the meetings concerning visual impacts (Exh. HO-E-76). Altresco maintained that there are no scenic vistas in the vicinity of the project area which would be significantly affected by the proposed facility (Exh. AL-2, at 13-25).

Altresco reported that it plans to paint the stacks light grey to reduce their visibility (id. at 13-22; Exh. AL-1, at 13). The Company indicated that visual screening on site would consist of an evergreen hedge along the GE property line parallel to Bennett Street, where the hedge is to be the same height as the existing eight-foot GE security fence (Exh. HO-E-37; Tr. 7, at 102).[239] Altresco stated that the Bennett Street landscaping plan is a condition of the Special Permit granted by the City of Lynn (Exhs. HO-B-9; HO-E-71a).[240] The Company further stated that the evergreen hedge is the only landscaping planned for the site (Tr. 1, at 96).

The record indicates that the proposed facility is surrounded by an industrial complex, whereby the proposed facility encompasses approximately 5.7 acres of the 223-acre complex. In addition, a significant buffer exists between the active site and the nearest non-GE developed land uses. The record further reflects that expected views of the proposed facility would blend with the industrialized nature of the GE River Works complex as well as surrounding industrialized areas. The Siting Board notes that the City of Lynn has authorized a stack height up to 14 feet higher than the proposed height contained in the record. Therefore, as a condition of proceeding with the proposed facility, Altresco must notify the Siting Board of any changes to the stack or to any other aspect of the proposed facility, based on the description in this proceeding, other than minor variations, so that the Siting Board may decide whether to inquire further into the issue. The Siting Board also requires that the evergreen hedge along Bennett Street be planted and maintained at the same height as the existing security fence.

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239 The Siting Board notes that the Company Initial Brief states that the hedge would be four feet high (at 174). However, testimony by Mr. Carroll states that the proposed hedge is to be as high as the existing security fence and that it is an eight-foot fence (Tr. 7, at 102).

240 The Siting Board notes that the height of the Bennett Street hedge is not delineated on the Landscaping Plan or in the Special Permit (Exhs. HO-E-71a; HO-B-9).

Therefore, in order to demonstrate that visual impacts are minimized at the proposed facility, Altresco should comply with the condition to plant and maintain the Bennett Street evergreen hedge at the same height as the security fence.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the aforementioned condition, the environmental impacts of the proposed facility would be minimized with respect to visual impacts.

f. Traffic

Altresco asserted that there would be no significant effect on local traffic due to the construction and operation of the proposed facility (Exh. HO-E-1, at 5-48; Tr. 6, at 56). Specifically, when the project is completed, the Company stated that levels of service ("LOS")[241] would not be reduced, nor would average delays increase appreciably at area intersections (Exh. HO-E-1, at 5-49).

In support of its assertions, Altresco presented estimates of projected trip generation and related traffic impacts, divided into construction-related traffic and facility operation-related traffic (id. at Appendix 5, Table 1-2). The Company asserted that its traffic study was conservative because it was developed for the previously planned 325 MW facility, therefore, computed vehicle trip figures most likely would be higher than what would be expected for a 170 MW facility (Exh. HO-E-27; Tr. 6, at 47-48).

Mr. Gotlieb indicated that according to UE&C, the bulk of the construction materials would arrive by train, and road access would be used only for those items unsuitable for train traffic (Tr. 3, at 64). The Company stated that in addition to the main line rail route along the GE River Works spur the Saugus branch may be utilized due to the size and weight

241 The Company indicated that the efficiency of traffic operations at a location is measured in terms of LOS (Exh. HO-E-1, App. 5, at 1-3). This refers to the quality of traffic flow along roadways and intersections and is described in terms of Levels A through F, where A represents the best possible conditions and F represents forced-flow or failing conditions (id.). LOS A-D is considered an acceptable operating condition according to stated traffic guidelines (id.).

constraints of the main line (Exh. HO-RR-19).[242] Altresco also acknowledged that some equipment may be shipped by barge to the Lynn dock, specifically the generator, the heaviest piece of equipment (Exh. BA-RR-3; Company Reply Brief at 14).

The Beach Association asserted that the Saugus branch was not presently used to carry freight, and might not support the shipment of large construction equipment (Beach Association Initial Brief at 8-9). Therefore, the Beach Association expressed the concern that trucks and barges would be required to move construction components, resulting in a nuisance and danger to the community (id. at 9). However, Altresco asserted that it would use only safe and efficient means of transporting the construction components (Company Reply Brief at 14). The Company indicated that while there is no regularly scheduled freight or passenger service on the Saugus branch, there can be intermittent freight service on occasion on the line (Exh. HO-RR-85).

Altresco indicated that the peak hours of construction related traffic would extend from 6:30 a.m to 7:30 a.m. and from 3:30 p.m. to 4:30 p.m. and encompass 316 vehicle round trips per day during the peak construction period (Exhs. HO-E-28; HO-E-1, App. 5 at 1-5). [243] Altresco further stated that 30 employees would work at the proposed facility, spread over three shifts, when it is fully operational (Exhs. HO-E-28; HO-E-1, App. 5, at 1-6). In addition to employee work trips, the Company indicated that operational traffic would include visitor trips and general delivery trips, for a total of 50 vehicle round trips per day (Exh. HO-E-1, App. 5, at 1-6). Finally, although the Company expects to need one oil

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[242] Altresco indicated that the weight and size limitations of the main line are determined by Guilford Transportation Industries, the former Boston and Maine Corporation (Exh. HO-RR-19). The weight limit is 263,000 pounds per car, including the weight of the car, and the size limitations are 15 feet 9 inches from the top of the rail and 9 feet wide (id.). The Saugus branch height limit is 17 feet from the top of the rail and 10 feet wide (id.).

[243] Altresco based its count of vehicle trips per day during peak construction on an estimated 400 construction employees at 1.33 employees per vehicle, and 16 trips per day by construction vehicles (Exh. HO-E-1, App. 5, at 1.5).

truck per hour, in the event that back-up oil deliveries are needed for up to five days a year, the Company projected two trucks per hour as a worst case scenario (id.; Exh. HO-RR-22).

To help quantify traffic generation, Altresco presented a comparison of expected peak-hour LOS traffic ratings for nine intersections, with and without the project, both during construction and for the first year of operation (Exh. HO-E-1, App. 5, at 3-1 to 3-5, Table 1-2). The Company identified site access points as the Bennett Street gate for construction workforce travel, the main GE gate -- located on Route 107 at Cooper Street/Fairchild Street - for heavy construction trucks, either the main gate or the Harding Street gate for operation employee travel, and the main gate for oil deliveries (id., App. 5, at 1-5).

Altresco indicated that one intersection, Route 107/Cooper Street/Fairchild Street, currently operates at an unacceptable level of service (LOS F) during the morning peak hour (id., App. 5 at 5-49). The Company stated that all other intersections would retain a generally acceptable level of service and would be only minimally influenced by the low volume of project traffic added under normal facility operations (id., App. 5, at 5-15).[244]

The Company indicated that the City of Lynn has submitted an application to the Massachusetts Department of Public Works to fund improvements to the Route 107/Cooper Street/Fairchild Street traffic system (Exh. HO-E-29).[245] Altresco asserted that it is committed to fund the improvements if state funding is not available (id.; Exh. HO-E-1, at 5-49). The Company therefore indicated that its selection of a mitigation option

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244 The Company presented documentation illustrating that only one intersection, located at Burns and Minot Streets, would undergo a change in the LOS during facility operation, dropping from a C to a D rating (Exh. HO-E-1, App. 5, at 1-9).

245 Two methods of improving the intersection are being considered, the first would increase the LOS from F to C and the second would increase the LOS from F to B (Exh. AL-8, at 3-4). The first method would improve the signal control phasing sequence without involving replacement or restoration of existing hardware, the second method is a more extensive signal control upgrade (id. at 4). The cost of the first method is estimated to be $10,000 and the cost of the second method is estimated to be between $175,000 - $200,000 (Exh. HO-RR-46).

concerning the type of upgrade, as well as the total cost to the Company, would be determined in conjunction with the City of Lynn (Exh. HO-RR-46). Mr. Lipka stated that the City is seeking state funding for the more enhanced improvements that would elevate the LOS to level B (Tr. 6, at 50).

The Company indicated that GE employs 3,500 production workers in three shifts, of which 2,100 of these employees work the 7:00 a.m. to 3:00 p.m. shift (Exh. HO-E-73). Further, an additional 3,500 salaried employees work from 7:30 a.m. to 4:15 p.m. (id.). However, Altresco stated that even with the construction work force peak travel occurring from 6:30 to 7:30 a.m and from 3:30 to 4:30 p.m., the influx of both GE and Altresco workers would not cause a traffic problem (Exh. HO-E-1, App. 5, at 1-6; Tr. 6, at 56). Further, Mr. Lipka stated that the impact of the project traffic in combination with the existing traffic was quantified by the results of the traffic analysis and demonstrates no deterioration at the intersections affected by construction traffic (Tr. 6, at 55).

The record indicates that both Altresco and the West Lynn Cogeneration project would be utilizing the same portion of a route along Circle Avenue for their effluent supply and return main pipelines (Exh. HO-RR-35).[246] Altresco noted that the Lynnway traffic would not be affected by the process water lines since the lines are to be jacked under the roadway (Exh. HO-RR-33). Finally, the Company asserted that MBTA traffic would not be affected by the construction or operation of the process water lines or the electric transmission lines (id.).

The Siting Board finds that increased vehicular traffic due to construction and operation at the proposed facility would not cause significant traffic impacts at key intersections in the vicinity of the facility, and further that LOS ratings would remain acceptable for an urban area. However, the Siting Board notes that although the

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[246] Originally the Company indicated that the routes would not be located in such proximity and, therefore, any coordination between the two facilities regarding street construction would not have been possible (Exh. HO-E-72). However, West Lynn Cogeneration has changed its preferred route to run along a portion of Circle Avenue, parallel to the Altresco water line (Exh. HO-RR-35).

transportation modeling supports the above conclusion, the combination of the sheer volume of GE personnel entering and exiting the complex and Altresco construction traffic produces a situation that should be monitored by the Company.

In addition, the Siting Board notes the need to upgrade the traffic signal at the Route 107/Fairchild Street/Cooper Street intersection, an access point which is integral to construction delivery traffic, Altresco employee traffic and oil deliveries. The issue of state funding versus Altresco funding should be resolved as soon as possible, as the upgrade should be in place by the time Altresco breaks ground. Therefore, the Siting Board requires that Altresco, in consultation with the City of Lynn, shall ensure funding for the final approved upgrade to the Route 107/Fairchild Street/Cooper Street intersection, prior to the start of construction, or as construction commences.

The Siting Board also notes the concerns expressed by the Beach Association regarding the transportation of large construction equipment in the event that rail transport is not feasible. Therefore, in the event that roadway or water travel is necessary to transport large construction equipment or components to the facility, the Siting Board requires that Altresco shall file with the Clerk of the Cities of Revere and Lynn and the Town of Saugus, and to provide copies to the Beach Association and other affected neighborhood associations, of a transportation plan that mitigates transportation impacts to the communities in question.

Finally, there is the possibility that a segment of Circle Avenue will be uprooted for the supply and return main pipelines for both Altresco and West Lynn Cogeneration. The Siting Board recommends that, to the extent practicable, the two companies work together to develop a schedule agreeable to both so that Circle Avenue is only subject to construction activity for a single timeframe.

Therefore, in order to minimize traffic impacts at the proposed facility, Altresco shall comply with (1) the condition that Altresco, in consultation with the City of Lynn, shall ensure funding for the final approved upgrade to the Route 107/Fairchild Street/Cooper Street intersection, prior to the start of construction, or as construction commences, and (2) the condition that Altresco file with the Clerks of the Cities of Revere and Lynn, and the Town of Saugus, and provide copies to the Beach Association and other affected neighborhood associations, a transportation plan that mitigates transportation impacts to the communities in question in the event that roadway or water travel is necessary to transport large construction equipment or components to the facility.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the aforementioned conditions, the environmental impacts of the proposed facility would be minimized with respect to traffic impacts.

g. Safety

The Company asserted that storage of any chemicals to be used by Altresco for water treatment or air pollution control -- aqueous ammonia, caustic, and acid -- would be contained in diked areas, which would be curbed and sealed to prevent accidental releases (Exhs. HO-E-1, at 5-20; HO-E-53). Altresco indicated that it proposes to store aqueous ammonia necessary for the SCR system on-site, in a 9,900 gallon single-wall, steel storage tank with a diked spill containment area (Exhs. HO-E-52; AL-2, at 13-26).[247] Further, the acid and caustic liquids required for plant operation would be stored in on-site bulk storage tanks sized to accept truckload deliveries, thereby requiring minimal operator handling and reducing the potential for spills and accidents (Exh. HO-E-1, at 5-20).

Altresco indicated that truck transport of the aqueous ammonia is the preferred method of transportation, and that the facility would require one 5,000-6,000 gallon shipment per week (Exh. HO-E-52). The Company asserted that the ammonia pumps and injection systems are specially designed to handle ammonia safely during usage on-site and that operators would be trained in emergency response techniques (Exh. AL-1, at 16).

Altresco indicated that the proposed facility would emit a small amount of ammonia to the atmosphere, but claimed that the level would not produce any ammonia odors (Tr. 6,

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247 The SCR system requires ammonia injection into the turbine exhaust system to reduce NO_X emissions (Exh. AL-2, at 13-25). Ammonia emissions from this process are referred to as ammonia slip (Tr. 6, at 31). The Company stated that aqueous ammonia, while more costly to store and handle than anhydrous ammonia, is safer due to the mixture of ammonia and water (Exh. HO-E-4, at 4-4).

at 30). The Company assumed that the ammonia emissions concentration would be ten parts per million, which is less than the DEP air toxics level for ammonia (id. at 31). Further, Altresco reported that the maximum predicted ground level 24-hour concentration is 1.63 ug/m^3, which is less than 30 percent of the allowable ambient limit (id. at 31; Exh. HO-E-4, at 4-4). The Company asserted that in the unlikely event of a failure of the ammonia storage facilities and subsequent release of ammonia, adequate precautions have been developed in the design of the ammonia storage facility to ensure public safety (Exh. HO-RR-83). Altresco further indicated that according to detailed modeling, the concentrations of ammonia at the site boundary would be 155 ppm, well below the 500 ppm level considered Immediately Dangerous to Life or Health (id. at 3).

Altresco indicated that it would develop a Spill Prevention Control and Countermeasure Plan and an Emergency Response Plan as required by the DEP (Exh. HO-E-54; Tr. 1, at 107). The Company stated that the plan which would be coordinated with existing GE emergency plans and procedures, would be submitted to the Lynn Fire Department and the DEP prior to the facility coming on-line (Exhs. AL-1, at 16; HO-E-54). The Company stated that all of its truck unloading facilities would be outfitted with the equipment necessary to prevent and contain spills that might occur during transfer (Tr. 1, at 110; Tr. 3, at 97). Finally, Altresco claimed that the proposed facility would not produce any on-going waste materials that are presently listed as hazardous (Exh. HO-E-55).[248]

[248] The Company stated that on occasion the facility would need to dispose of O&M wastes that are determined to be hazardous or potentially flammable or corrosive (Exh. HO-E-55). Therefore, the proposed facility would be considered a very-small-quantity generator of federally regulated hazardous waste and a small-quantity generator of state regulated waste (id.). The Company stated that it would comply with the regulations associated with the above designations by transporting and disposing of the small qualities of hazardous waste and waste oil with Clean Harbors, a licensed hazardous waste transporter (id.).

Altresco asserted that any hazardous materials found on-site that were generated from prior GE operations would not affect construction of the proposed facility (Exh. HO-E-84).[249] The Company stated that, based on Wehran Engineering Corporation's ("Wehran") environmental assessment of the lease area, the Company would be able to seal the site, cap the area, and keep the facility completely contained and separate from the existing GE soil and groundwater (Exh. HO-E-95; Tr. 1, at 109). Mr. Hill stated that a soil and groundwater plan is required and would be developed by Wehran before any disposition of excavated material would occur (Tr. 2, at 14). In addition, within the same time frame, a health and safety plan would be developed; both plans would be activated prior to construction and monitored by DEP (id. at 15 and 16).

The Siting Board notes that Altresco has described the major physical characteristics of its chemical storage and handling facilities. The design of the proposed facilities includes measures to avert spills of hazardous materials and to contain any such accidental spills. Further, the Siting Board notes that Altresco intends to develop emergency plans similar to the plans found acceptable in previous Siting Board decisions. Enron, 23 DOMSC at 220; MASSPOWER, 20 DOMSC at 399-401; Altresco-Pittsfield, 17 DOMSC at 406-408.

In addition, the Company has demonstrated that it will take appropriate measures during the construction of the facility to avoid potential hazards resulting from any existing site contamination. The Siting Board notes that the plans to be developed -- the soil and groundwater plan and the health and safety plan, must be implemented prior to construction and monitored by DEP.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the above mitigation, the environmental impacts of the proposed facility would be minimized with respect to safety.

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249 The entire GE River Works complex is classified as a hazardous waste site under G.L. c. 21E, DEP case 3-0357 (Tr. 1, at 42). The site is presently under a DEP waiver, which allows GE to move forward with remediation under an approved protocol (id.). Altresco stated that it would follow relevant aspects of applicable protocol during construction and operation (id.).

h. Electric and Magnetic Fields[250]

Altresco stated that new 115 kV cables -- enclosed in overhead conduit banks -- would be used to connect the four main power transformers at the proposed facility to the existing GE switchyard, from where a new 115 kV, 1,800-feet long, overhead electrical transmission interconnect ("interconnect") would extend to NEPCo's regional 115 kV transmission system (Exh. AL-2, at 3-21; AL-3, fig. 3-5). Altresco added that the new 115 kV interconnect would be similar to lines which presently exist at the site (Exh. AL-1, at 17).

The Company provided the Siting Board with magnetic field calculations, indicating an expected level of 16 milligauss ("mG") directly under the interconnect, based on a nominal power output of 170 MW from the proposed facility (id.; Exh. HO-E-59; Tr. 2, at 9).[251,252] Altresco stated that, under a 1990 interconnect agreement with NEPCo, the Company has reserved 240 MW of transmission access within the existing 115 kV regional transmission system (Exh. HO-E-59).[253]

Altresco stated that no off-site transmission line improvements are presently anticipated as a result of the proposed facility's operation, and asserted that no changes in

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250 Electric fields and magnetic fields produced by the presence of voltage and the flow of current are collectively known as electromagnetic fields or "EMF".

251 The Siting Board notes that EMF measurements, or calculations, based at a point directly below the power line(s), will typically yield a higher value of both electric field and magnetic field units than those based at a point diagonally opposite of the power line(s), such as the edge of a ROW.

252 Altresco indicated that the expected 16 mG level under the interconnect would be well below the 200 mG edge-of-ROW limits adopted by the states of Florida and New York (Exh. AL-1, at 17).

253 Altresco indicated that, although it has contracted for 240 MW of transmission access, the estimated nominal plant electrical output would be 170 MW, yielding the Company a transmission access reserve of 70 MW (Exhs. AL-2, at 1-2; HO-E-59).

off-site EMF would be expected (Exh. AL-1, at 17). In support, the Company provided a directional power flow study proposed by NEPCo concerning expected power and current levels on the existing transmission lines to which the proposed facility would be connected in 1996 -- the assumed Altresco start-up year (Exh. HO-V-25, Tables V-25a,b). Altresco indicated that the study assumed a nominal power output of 240 MW for the proposed facility (id.). The study indicates that under a worst-case scenario, power flows on one of the 115 kV transmission lines to which the proposed facility would be connected could approach 190 MW (id.).

In a previous review of proposed transmission line facilities which included 345 kV transmission lines, the Siting Council accepted edge of right-of-way levels of 1.8 kV/meter for the electric field, and 85 milligauss for the magnetic field. Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985) ("1985 MECo Decision"). Here, the Company has provided an estimate of the expected magnetic field level under its proposed interconnect of 16 mG -- well below the level found acceptable in the 1985 MECo Decision.
With respect to existing NEPCo transmission lines,[254] the NEPCo analysis provided by the Company indicates maximum power flows of 190 MW on 115 kV transmission lines in the area, assuming operation of a 240 MW facility consistent with Altresco's transmission agreement. Based on operation of a 170 MW facility, as currently proposed, maximum power flows along the existing transmission system would be considerably less than 190 MW, and thus, likely would not exceed the power flows reflected in the EMF analysis for the interconnect. Further, it is likely that magnetic field impacts of the proposed facility on

[254] The Siting Board notes that NEPCo's existing transmission lines are not ancillary facilities as defined in G.L. c. 164, § 69G. However, in order to allow comprehensive analysis of environmental impacts associated with the construction and operation of the proposed generating facility, the Siting Board may identify and evaluate any potentially significant effects of the facility on EMF levels along existing transmission lines. See Boston Edison (Phase II) at 139, 183 (1993).

the existing 115 kV NEPCo transmission lines in the area would be well within levels the Siting Council found acceptable in the 1985 MECo Decision.[255]

Although the Company failed to provide expected electric field levels for the interconnect, the Siting Board notes that the proposed interconnect would be similar to 115 kV interconnect lines which presently exist at the site, and therefore, no significant change in electric field levels from those which presently exist would be likely. In addition, because no changes in voltages on the existing transmission system would be required, no change in electric field levels along that system would be expected.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to EMF.

i. Conclusion

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility, including mitigation measures and facility design, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized as itemized above.

The Siting Board has found that, based on the above mitigation measures, conditions, and facility design, the environmental impacts of the proposed facility would be minimized with respect to air quality (with the exception of CO_2), water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, and EMF.

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[255] In previous reviews addressing EMF effects of proposed power flows on 115 KV transmission facilities, magnetic field estimates have ranged from 3 mG to 56 mG, representing expected levels at locations under the transmission lines and along the edge of ROW. Enron, 23 DOMSC at 225-227; NEPCo, 21 DOMSC at 405-407, 413-414; MASSPOWER, 20 DOMSC at 401-403; Turners Falls, 18 DOMSC at 190-191; Commonwealth Electric, 17 DOMSC at 328-331.

3. Cost Analysis of the Proposed Facilities

In this section the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance would be achieved between environmental impacts and cost.

Altresco estimated that the installation costs of the proposed facilities, which include project development as well as construction costs, would total approximately $181.8 million, reflecting a start-up date of January 1, 1996 (Exh. HO-RR-88). The Company indicated that the use of sub-assembly construction techniques allows the project to be completed in a cost-efficient and timely manner (Exh. HO-V-4). Altresco provided itemized costs of the construction and engineering aspects of the project developed by their EPC contractor (Exh. HO-C-2). In addition, the Company provided the itemized costs associated with the major plant components (id.). Finally, Altresco provided itemized costs for fuel and water costs, site costs, lease payments, interest payments, permitting costs, development costs and contingency funds (id.). The Company asserted that the construction cost estimates incorporate the expected changes associated with mitigating the identified environmental impacts at the preferred site (Company Initial Brief at 117).

In regard to operating costs, Altresco noted several project attributes which would serve to minimize such costs. The Company stated that the proposed site is located adjacent to the GE steam lines and the existing GE power house thereby minimizing steam transportation costs (Exh. AL-2, at 12-11). Altresco stated that the cost of steam transportation, for both installation and operating costs, increases as the distance from the steam host increases (Exh. HO-S-11). The Company provided an analysis detailing that, as the distance increases from 700 feet to 9,500 feet, the cost, including export line capital cost and operating cost for the first year, increases from $107,000 to $776,000, over the project base-line cost (id.)

Altresco also noted that the proposed project would utilize treated sewage effluent from the LWSC treatment plant for process water, thereby helping to conserve potable water supplies (Exh. HO-E-1, at 2-2). The Company provided an analysis establishing $250,000 for the cost of the effluent per year, $50,000 for operating costs of treating the effluent per year, and $2 million for installing the treatment facilities, versus $835,000 per year if Altresco used potable water only, thereby further minimizing operating costs (Exh. HO-C-2).

Altresco provided various economic analyses comparing the estimated construction and operating costs of the proposed facility with the costs of a generic 170 MW gas-fired combined cycle facility, (Exhs. AL-40, attach. RLC-5 and 6; HO-PA-3; HO-RR-87a).[256] The analyses are based on estimates from the 1992 GTF Report, and include capital costs, fuel, O&M, and other factors (id.). The Company asserted that the 20-year levelized costs of the Altresco facility are considerably less than the levelized cost of the generic facility, as the analyses indicated that the levelized cost in 1996 dollars of the proposed facility is $74.31/MWH, as opposed to $95.86/MWH for the generic facility (id.). The Company identified Altresco's fuel contract as one of the primary factors contributing to its facility's low costs and to a lesser extent, the higher projected availability of the Altresco facility (see Section II.C.3.b for a discussion of the Altresco fuel contract) (Exh. PA-3).

The Company has provided estimates of the overall costs of the proposed facility. In addition, the Company has provided estimates of the cost of utilizing effluent versus potable water to supply process water at the site.

The Siting Board finds that Altresco has provided sufficient information on the costs of the proposed project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

4. Conclusions on the Proposed Facility

In this section, we review the consistency of the proposed facility with our overall review standard, requiring that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as trade-offs between these environmental impacts and cost.

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256 The economic analyses also included a comparison of the proposed facility with various other generation alternatives, as described in Section II.B., above (Exh. AL-40, RLC-5, RLC-6).

The Siting Board has found that based on the implementation of the above mitigation measures and facility design, and with the implementation of the conditions specified in Sections III.C.2.f and g, the environmental impacts of the proposed facility would be minimized with respect to water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, and EMF. The Siting Board also has found that, based on the implementation of the above mitigation measures and facility design, the environmental impacts of the proposed facility would be minimized with respect to air quality impacts, with the exception of CO_2 impacts.

In addition, the Siting Board has found that Altresco has provided sufficient information on the costs of the proposed project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

The record indicates that there are no significant issues involving the balance among water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, EMF, and air quality impacts other than CO_2, nor between any of these concerns and cost. Further, the Siting Board notes that the use of treated effluent over the long term is both economically and environmentally beneficial, as the use of treated effluent contributes to the conservation of potable water and a reduced flow of wastewater into Lynn Harbor. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, EMF, and air quality impacts, other than CO_2, consistent with minimizing cost and other environmental impacts.

With respect to CO_2 emissions, the Siting Board has found that Altresco did not establish that the CO_2 emissions impacts of the proposed facility would be minimized. Thus, the Siting Board considers whether Altresco's proposed level of CO_2 mitigation or a higher level of CO_2 mitigation would allow Altresco to establish that the CO_2 emissions impacts of the proposed facility would be minimized consistent with minimizing cost.

The Siting Board recognizes that, like EEC, Altresco filed its initial petition prior to the Siting Council's establishment of general criteria for CO_2 mitigation in EEC Compliance. Thus, while we will consider those criteria here, we recognize that any determination of an appropriate level of CO_2 offsets for Altresco's proposed facility should bear a reasonable relationship to the level of CO_2 offsets required of EEC in EEC Compliance.

One method for such a determination of an appropriate level of mitigation would be to calculate a ratio between the maximum potential CO_2 emissions offset responsibilities for Altresco's proposed facility and the EEC project, and apply such ratio to adjust the actual CO_2 mitigation level approved in EEC Compliance. However, because that approach would involve comparing the proposed gas-fired project to a coal-fired project, the various determinants of an appropriate level of CO_2 mitigation as identified in the Siting Council's guideline -- facility cost, total CO_2 emissions, and net-of-displacement emissions -- involve very different ratios. For example, while the proposed facility would emit approximately half of the CO_2 of the EEC project on a MW-for-MW basis, the proposed facility potentially would displace up to 150 percent of its CO_2 emissions while the EEC project potentially would displace a maximum of 74 percent of its CO_2 emissions. However, there is no guarantee that the proposed facility will displace CO_2 emissions over the life of the project. Therefore, unless clearly supported as part of a project proponent's dispatch analysis, net-of-displacement emissions should not have an overriding weight in consideration of the appropriate level of CO_2 emissions offsets.[257]

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[257] Use of a weighted ratio based on two or more factors provides a means to reflect the divergent ratios, but is very sensitive to the particular combination of factors and weights. The use of a weighted ratio is illustrated by the following hypothetical weighting for the two facilities. Assume that the weighted ratio is to be based on an equal weighting of two factors -- total emissions and net-of-displacement emissions. The record indicates that the emissions from generation displaced by the proposed facility would be 150 percent of that from the proposed facility. The emissions from generation displaced by the EEC project would be 74 percent of that from the EEC project. EEC Compliance, 25 DOMSC at 354. The weighted maximum offset responsibility of the proposed facility would be 25 percent, the average of a 100 percent maximum offset responsibility based on total emissions and a (-)50 percent maximum offset responsibility based on net-of-displacement emissions. The weighted maximum offset responsibility of the EEC project would be 63 percent, the average of a 100 percent maximum offset responsibility based on total emissions and a 26 percent maximum offset responsibility based on net-of-displacement emissions. The ratio between the weighted maximum offset responsibility of 63 percent for the EEC project

Further, given the limited record on CO_2 in this review and the availability of only one precedent case that began to develop a guideline for determining an appropriate level of CO_2 mitigation, the Siting Board does not intend to set forth herein a precise ratio of CO_2 mitigation between coal-fired and gas-fired generation. For purposes of this review, however, the Siting Board finds that it is reasonable to consider both the relative facility costs and the relative facility CO_2 emissions of the proposed project and the EEC project in evaluating the appropriate level of CO_2 mitigation.

The Siting Board notes that the required CO_2 mitigation in EEC Compliance would offset approximately 0.8 percent of that facility's CO_2 emissions, or 19,912 tpy at a cost of $2,000,000. EEC Compliance, 25 DOMSC at 354, 367. See Section III.C.2.a.(2)(a). However, the Siting Board recognized in EEC Compliance that the EEC project would require on-site clearing of 50 acres, or an estimated 15,000 trees. Id. at 350, 366. Based on Altresco's assumption that a planted tree provides 0.75 tpy of CO_2 offsets, up to 11,250 tpy of the required offsets in EEC Compliance would be negated by such tree clearing, resulting in a net offset level for the EEC project of as low as 8,662 tpy, or 0.348 percent of the EEC facility's CO_2 emissions.

Here, Altresco's proposed facility would emit 627,500 tpy of CO_2. Based on the approximate percentage of total emissions reflected in the offset requirement in EEC Compliance, 0.8 percent, Altresco's offset requirement would be 5,020 tpy. However, recognizing that the proposed facility requires little or no tree clearing, the net offset requirement for the EEC project of 0.348 percent is more appropriate for Altresco, resulting in an offset requirement of 2,184 tpy for the proposed facility.

Based on the Company's assumption that a planted tree offsets 0.75 tpy of CO_2, planting 2,912 trees would offset 2,184 tpy. Based on the Company's assumed cost of $100 per tree, a contribution of $291,200 to MassReleaf would provide the necessary offsets.

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and the weighted maximum offset responsibility of 25 percent for the proposed facility would be 2.5-to-one.

As part of considering a possible increase in Altresco's proposed CO_2 mitigation level, the Siting Board considers the possible effect of the cost of any such additional mitigation on project viability and the proponent's ability to mitigate other environmental impacts. EEC Compliance, 25 DOMSC at 364-365. The Siting Board notes that the $291,200 cost to mitigate 0.348 percent of the facility's CO_2 emissions is less than one-sixth of a percent of the total estimated cost of the proposed facility, as compared to the approximate one-third of a percent of the $593 million project cost that EEC was required to provide for CO_2 mitigation. EEC, 22 DOMSC at 327. Further, based on cost information contained in the record, the Siting Board notes that the $291,200 CO_2 offset cost would have no apparent effect on the viability of the project or the Company's ability to mitigate other environmental impacts.

Thus, the Siting Board finds that implementation by Altresco of a CO_2 mitigation plan to provide, in equal annual installments over the first five years after start-up or sooner, CO_2 offsets for at least 0.348 percent of the total CO_2 emissions from the proposed facility, using the approach presented by Altresco -- that is MassReleaf -- would be consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost. Should Altresco choose as an alternative to implementation of the above CO_2 mitigation approach, to present a modified CO_2 mitigation plan and supporting analysis that includes a different mix of approaches, other than the MassReleaf approach alone, for providing the required offsets of 0.348 percent of total CO_2 emissions, the Siting Board will review such plan and analysis to determine if it is consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost.

Accordingly, the Siting Board finds that with implementation of the requirement that the Company provide offsets of at least 0.348 percent of the total CO_2 emissions from the proposed facility, the environmental impacts of the CO_2 emissions from the proposed facility would be minimized consistent with minimizing cost.

Therefore, based on compliance with the above condition and the conditions in Sections III.C.2.f and g, the environmental impacts of the proposed facility would be minimized consistent with cost.

IV. DECISION

The Energy Facilities Siting Board hereby CONDITIONALLY APPROVES the petition of Altresco Lynn, Inc. to construct a 170 megawatt bulk generating facility and ancillary facilities in Lynn, Massachusetts. The CONDITIONS set forth in this decision are as follows:

(A) In order to establish that the proposed project will provide a necessary energy supply for the Commonwealth, and that its proposed project is financiable, the Company shall submit to the Siting Board either (1) a signed and approved contract with BECo for 132 MW, or (2) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electrical output.

(B) In order to establish that the proposed project will have an adequate water supply and, therefore, is likely to be constructed within applicable time frames and be capable of meeting performance objectives, the Company shall provide the Siting Board with a signed copy of the agreement between Altresco and LWSC for provision of treated effluent and potable water.

In order to comply with conditions (A) and (B), the Company shall submit the necessary information with the Siting Board within four years from the date of this conditional approval. At that time, the Siting Board shall review the information and determine if the Company has complied. The Company will not receive final approval of its project until it complies with these conditions.

In addition, the Company shall comply with the following conditions during construction and operation of the proposed facility:

(C) In order to establish that visual impacts are minimized, the Siting Board requires that the evergreen hedge along Bennett Street be planted and maintained at the same height as the existing security fence.

(D) In order to establish that traffic impacts are minimized, Altresco shall (1) in consultation with the City of Lynn, ensure funding for the final approved upgrade to the Route 107/Fairchild Street/Cooper Street intersection, prior to the start of construction, or as construction commences; and (2) file with the Clerks of the Cities of Revere and Lynn and the Town of Saugus, and provide copies to the Beach Association and other affected neighborhood associations, a transportation plan that mitigates transportation impacts to the communities in question in the event that roadway or water travel is necessary to transport large construction equipment or components to the facility.

(E) In order to establish that CO_2 emissions are minimized, Altresco shall implement a CO_2 mitigation plan to provide, in equal installments over the first five years after start-up or sooner, CO_2 offsets for at least 0.348 percent of the total CO_2 emissions from the proposed facility using the approach presented by the Company -- the MassReleaf program. Should Altresco choose to present a modified CO_2 mitigation plan and supporting analysis that includes an approach or mix of approaches other than the MassReleaf program alone, for providing the required offsets of 0.348 of total CO_2 emissions, the Siting Board will review such plan and analysis to determine if it is consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost.

Upon completion of construction and prior to initial operation of the proposed project, Altresco shall notify the Siting Board regarding its compliance with conditions (C), (D), and (E).

In addition, the Siting Board 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 as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

Robert W. Ritchie

Robert W. Ritchie
Hearing Officer

Dated this 15th day of December, 1993

APPROVED by the Energy Facilities Siting Board at its meeting of December 14, 1993, by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, EFSB/DPU); Barbara Kates-Garnick (Commissioner, DPU); Stephen Remen (for Gloria Larson, Secretary of Economic Affairs); Andrew Greene (for Trudy Coxe, Secretary of Environmental Affairs); Joseph Faherty (Public Member); and William Sargent (Public Member). Voting against approval of the Tentative Decision as amended: Mary Clark Webster (Commissioner/DPU).

Kenneth Gordon, Chairman
Energy Facilities Siting Board

Dated this 14th day of December, 1993

TABLE 1

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1996

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	1,246	1,487	1,715
Ref	B	913	1,154	1,382
Mult Regr		227	468	696
End Yr Lin	H	(231)	10	238
High-Low Av	H	(278)	(37)	191
End Yr Lin	B	(565)	(324)	(96)
High-Low Av	B	(612)	(371)	(143)
Lin Regr		(923)	(682)	(454)
CAGR Regr		(2,246)	(2,005)	(1,777)
High Demand	H	(3,639)	(3,639)	(3,411)
High Demand	B	(3,973)	(3,973)	(3,745)

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	911	1,152	1,407
Ref	B	682	757	1,012
Mult Regr		(537)	(296)	(41)
End Yr Lin	H	(657)	(499)	(244)
High-Low Av	H	(1,036)	(878)	(623)
End Yr Lin	B	(1,052)	(894)	(639)
Lin Regr		(1,391)	(1,233)	(978)
High-Low Av	B	(1,431)	(1,273)	(1,018)
CAGR Regr		(2,984)	(2,826)	(2,571)
High Demand	H	(5,423)	(5,247)	(4,992)
High Demand	B	(5,818)	(5,642)	(5,387)

TABLE 1 (page 2)

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	165	356	612
Ref	B	(288)	(97)	159
End Yr Lin	H	(1,318)	(1,127)	(871)
Mult Regr		(1,396)	(1,205)	(949)
End Yr Lin	B	(1,771)	(1,580)	(1,324)
High-Low Av	H	(1,799)	(1,608)	(1,352)
Lin Regr		(2,094)	(1,903)	(1,647)
High-Low Av	B	(2,252)	(2,061)	(1,805)
CAGR Regr		(3,981)	(3,790)	(3,534)
High Demand	H	(6,517)	(6,341)	(6,085)
High Demand	B	(6,970)	(6,794)	(6,538)

1999

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	(592)	(401)	(119)
Ref	B	(1,100)	(909)	(627)
End Yr Lin	H	(1,855)	(1,664)	(1,382)
Mult Regr		(2,239)	(2,048)	(1,766)
End Yr Lin	B	(2,362)	(2,171)	(1,889)
High-Low Av	H	(2,484)	(2,293)	(2,011)
Lin Regr		(2,673)	(2,482)	(2,200)
High-Low Av	B	(2,991)	(2,800)	(2,518)
CAGR Regr		(4,880)	(4,689)	(4,407)
High Demand	H	(7,522)	(7,346)	(7,064)
High Demand	B	(8,029)	(7,853)	(7,571)

TABLE 1 (page 3)

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	(1,149)	(958)	(670)
Ref	B	(1,714)	(1,523)	(1,235)
End Yr Lin	H	(2,410)	(2,219)	(1,382)
End Yr Lin	B	(2,975)	(2,784)	(2,496)
High-Low Av	H	(3,005)	(2,814)	(2,526)
Mult Regr		(3,128)	(2,937)	(2,649)
Lin Regr		(3,270)	(3,079)	(2,791)
High-Low Av	B	(3,570)	(3,379)	(3,091)
CAGR Regr		(5,822)	(5,631)	(5,343)
High Demand	H	(8,315)	(8,139)	(7,851)
High Demand	B	(8,880)	(8,704)	(8,416)

Notes: Low supply, base supply, high supply cases include 83 MW -- the committed capacity of Enron.

Sources: Exhs. AL-13, attach. RLC-26; HO-RR-82.

TABLE 2

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1996

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	1,246	1,487	1,781
Ref	B	1,137	1,378	1,672
Mult Regr		227	468	762
End Yr Lin	H	(231)	10	304
High-Low Av	H	(279)	(38)	256
End Yr Lin	B	(337)	(96)	198
High-Low Av	B	(388)	(147)	147
Lin Regr		(923)	(682)	(388)
CAGR Regr		(2,246)	(2,005)	(1,711)

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	911	1,152	1,473
Ref	B	786	1,027	1,348
Mult Regr		(537)	(296)	25
End Yr Lin	H	(740)	(499)	(178)
End Yr Lin	B	(866)	(625)	(304)
High-Low Av	H	(1,120)	(879)	(558)
High-Low Av	B	(1,246)	(1,005)	(684)
Lin Regr		(1,474)	(1,233)	(912)
CAGR Regr		(3,067)	(2,826)	(2,505)

TABLE 2 (page 2)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	272	463	785
Ref	B	131	322	644
End Yr Lin	H	(1,204)	(1,013)	(691)
Mult Regr		(1,282)	(1,091)	(769)
End Yr Lin	B	(1,351)	(1,160)	(838)
High Low Av	H	(1,684)	(1,493)	(1,171)
High Low Av	B	(1,847)	(1,656)	(1,334)
Lin Regr		(1,977)	(1,786)	(1,464)
CAGR Regr		(3,856)	(3,665)	(3,343)

1999

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	(371)	(180)	168
Ref	B	(525)	(334)	14
End Yr Lin	H	(1,623)	(1,432)	(1084)
End Yr Lin	B	(1,790)	(1,599)	(1,251)
Mult Regr		(2,005)	(1,814)	(1,466)
High Low Av	H	(2,248)	(2,057)	(1,709)
High Low Av	B	(2,402)	(2,211)	(1,863)
Lin Regr		(2,434)	(2,243)	(1,895)
CAGR Regr		(4,623)	(4,432)	(4,084)

TABLE 2 (page 3)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	**(811)**	**(620)**	**(266)**
Ref	B	**(978)**	**(787)**	**(433)**
End Yr Lin	H	**(2,057)**	**(1,866)**	**(1,512)**
End Yr Lin	B	(2,243)	(2,052)	(1,698)
High Low Av	H	(2,643)	(2,452)	(2,098)
Mult Regr		(2,765)	(2,574)	(2,220)
High Low Av	B	(2,811)	(2,620)	(2,266)
Lin Regr		(2,905)	(2,714)	(2,360)
CAGR Regr		(5,426)	(5,235)	(4,881)

NOTES: Bold signifies deficiency of at least 170 MW.

Table 2 incorporates the following changes from Table 1: (1) Reserve margins adjusted as follows: 22 percent in 1996 and 1997, 21.5 percent in 1998, 21 percent in 1999, and 20.5 percent in 2000; (2) base DSM case discounts DSM increment over 1991 by 8.4 percent; (3) high supply case includes uncommitted portion of MASSPOWER and Enron.

SOURCES: Exhs. AL-13, attachs. RLC-17(c), RLC-19, RLC-23; HO-RR-61, at 1; HO-RR-65; HO-RR-82.

TABLE 3

SUMMARY OF 1996 NPV ECONOMIC EFFICIENCY SAVINGS
UNDER COMPANY SCENARIOS FOR 1996-2015
($ MILLIONS)

Demand Forecast	Fuel Price	NPV Savings	First Year of Continuous Savings Annual	First Year of Continuous Savings Cumulative
Declining Carrying Charge Method				
1992 CELT	DRI	90.0	2000	2003
1992 CELT	WEFA	48.5	1999	2003
High-Low Average	DRI	129.0	1996	1996
High-Low Average	WEFA	87.6	1996	1996
1990 CELT	DRI	161.4	1996	1996
1990 CELT	WEFA	116.0	1996	1996
NEPOOL Deficiency Charge Method				
1992 CELT	DRI	152.5	2000	2003
1992 CELT	WEFA	110.1	1999	2003
High-Low Average	DRI	191.6	1999	2001
High-Low Average	WEFA	149.3	1998	1999
1990 CELT	DRI	224.0	1998	1999
1990 CELT	WEFA	177.7	1999	1999

SOURCE: Exh. HO-RR-60

TABLE 4

1996 NPV ENERGY COSTS AND CAPACITY COST EFFECTS
UNDER REFERENCE FORECAST FOR 1996-1999
($ THOUSANDS)

	Altresco Total Fixed and Energy Cost	Displaced Energy Cost DRI	Displaced Energy Cost WEFA	Avoided Capacity Cost-Carrying Charge Method	Avoided Capacity Cost - Deficiency Charge Method
1996	72,292	44,220	43,220	26,316	20,230
1997	69,388	43,068	44,158	22,714	19,126
1998	68,389	45,985	47,224	19,792	18,083
1999	65,769	48,325	49,152	17,258	17,097
Cummulative	275,838	181,598	183,754	86,080	74,536

SOURCE: Exh. HO-RR-60

TABLE 5

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-1998

1996

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref H	(682)	(50)	103	(412)	200
Ref B	(822)	(190)	(37)	(552)	60
Ref L	(950)	(317)	(164)	(679)	(67)
EndYr H	(961)	(328)	(175)	(690)	(78)
EndYr B	(1,049)	(417)	(264)	(778)	(167)
ExVal H	(1,054)	(421)	(268)	(783)	(171)
EndYr L	(1,118)	(485)	(332)	(847)	(235)
ExVal B	(1,194)	(561)	(408)	(923)	(311)
ExVal L	(1,321)	(689)	(536)	(1,050)	(439)
Lin Regr	(1,334)	(701)	(548)	(1,063)	(451)
CAGR Regr	(1,779)	(1,147)	(994)	(1,508)	(897)

1997

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref H	(871)	(239)	29	(664)	11
Ref B	(1,039)	(407)	(139)	(831)	(157)
Ref L	(1,188)	(556)	(288)	(980)	(306)
EndYr H	(1,222)	(590)	(322)	(1,014)	(340)
EndYr B	(1,335)	(703)	(435)	(1,127)	(453)
ExVal H	(1,368)	(736)	(468)	(1,160)	(486)
EndYr L	(1,423)	(791)	(523)	(1,215)	(541)
ExVal B	(1,536)	(903)	(636)	(1,328)	(653)
Lin Regr	(1,552)	(920)	(652)	(1,344)	(670)
ExVal L	(1,685)	(1,053)	(785)	(1,477)	(803)
CAGR Regr	(2,083)	(1,451)	(1,183)	(1,875)	(1,201)

TABLE 5 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-1998

1998

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref H	**(1,181)**	**(548)**	**(281)**	**(1,060)**	**(298)**
Ref B	**(1,373)**	**(741)**	**(473)**	**(1,252)**	**(491)**
EndYr H	**(1,482)**	**(849)**	**(582)**	**(1,361)**	**(599)**
Ref L	**(1,542)**	**(910)**	**(642)**	**(1,421)**	**(660)**
EndYr B	**(1,621)**	**(988)**	**(721)**	**(1,499)**	**(738)**
ExVal H	**(1,688)**	**(1,056)**	**(788)**	**(1,567)**	**(806)**
EndYr L	**(1,729)**	**(1,096)**	**(829)**	**(1,608)**	**(846)**
Lin Regr	(1,763)	(1,130)	(863)	(1,642)	(880)
ExVal B	**(1,881)**	**(1,248)**	**(981)**	**(1,759)**	**(998)**
ExVal L	(2,049)	(1,417)	(1,149)	(1,928)	(1,167)
CAGR Regr	(2,385)	(1,753)	(1,485)	(2,264)	(1,503)

Bold signifies deficiency of at least 170 MW.

SOURCE: JH-RR-2(c) to 2(n)

TABLE 6

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000
1996

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(660)	(28)	270
Ref B	(724)	(92)	206
EndYr H	(922)	(290)	8
Ref L	(935)	(303)	(5)
EndYr B	(978)	(346)	(48)
ExVal H	(1,031)	(399)	(101)
EndYr L	(1,061)	(429)	(131)
ExVal B	(1,095)	(463)	(165)
ExVal L	(1,306)	(674)	(376)
Lin Regr	(1,334)	(702)	(404)
CGR Regr	(1,780)	(1,148)	(850)

1997

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(848)	(216)	82
Ref B	(920)	(288)	108
Ref L	(1,142)	(510)	(212)
EndYr H	(1,173)	(541)	(243)
EndYr B	(1,244)	(612)	(314)
ExVal H	(1,345)	(713)	(415)
EndYr L	(1,350)	(718)	(420)
ExVal B	(1,417)	(785)	(487)
Lin Regr	(1,553)	(921)	(623)
ExVal L	(1,639)	(1,007)	(709)
CGR Regr	(2,083)	(1,451)	(1,153)

TABLE 6 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(1,099)	(467)	(169)
Ref B	(1,185)	(553)	(255)
EndYr H	(1,371)	(739)	(441)
Ref L	(1,416)	(784)	(486)
EndYr B	(1,457)	(825)	(527)
EndYr L	(1,587)	(955)	(657)
ExVal H	(1,605)	(973)	(675)
ExVal B	(1,691)	(1,059)	(761)
Lin Regr	(1,711)	(1,079)	(781)
ExVal L	(1,922)	(1,290)	(992)
CGR Regr	(2,331)	(1,699)	(1,401)

1999

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(1,368)	(736)	(390)
Ref B	(1,489)	(857)	(511)
EndYr H	(1,580)	(948)	(602)
EndYr B	(1,682)	(1,050)	(704)
Ref L	(1,731)	(1,099)	(753)
EndYr L	(1,837)	(1,205)	(859)
ExVal H	(1,855)	(1,223)	(877)
Lin Regr	(1,877)	(1,245)	(899)
ExVal B	(1,976)	(1,344)	(998)
ExVal L	(2,218)	(1,586)	(1,240)
CGR Regr	(2,591)	(1,959)	(1,613)

TABLE 6 (page 3)

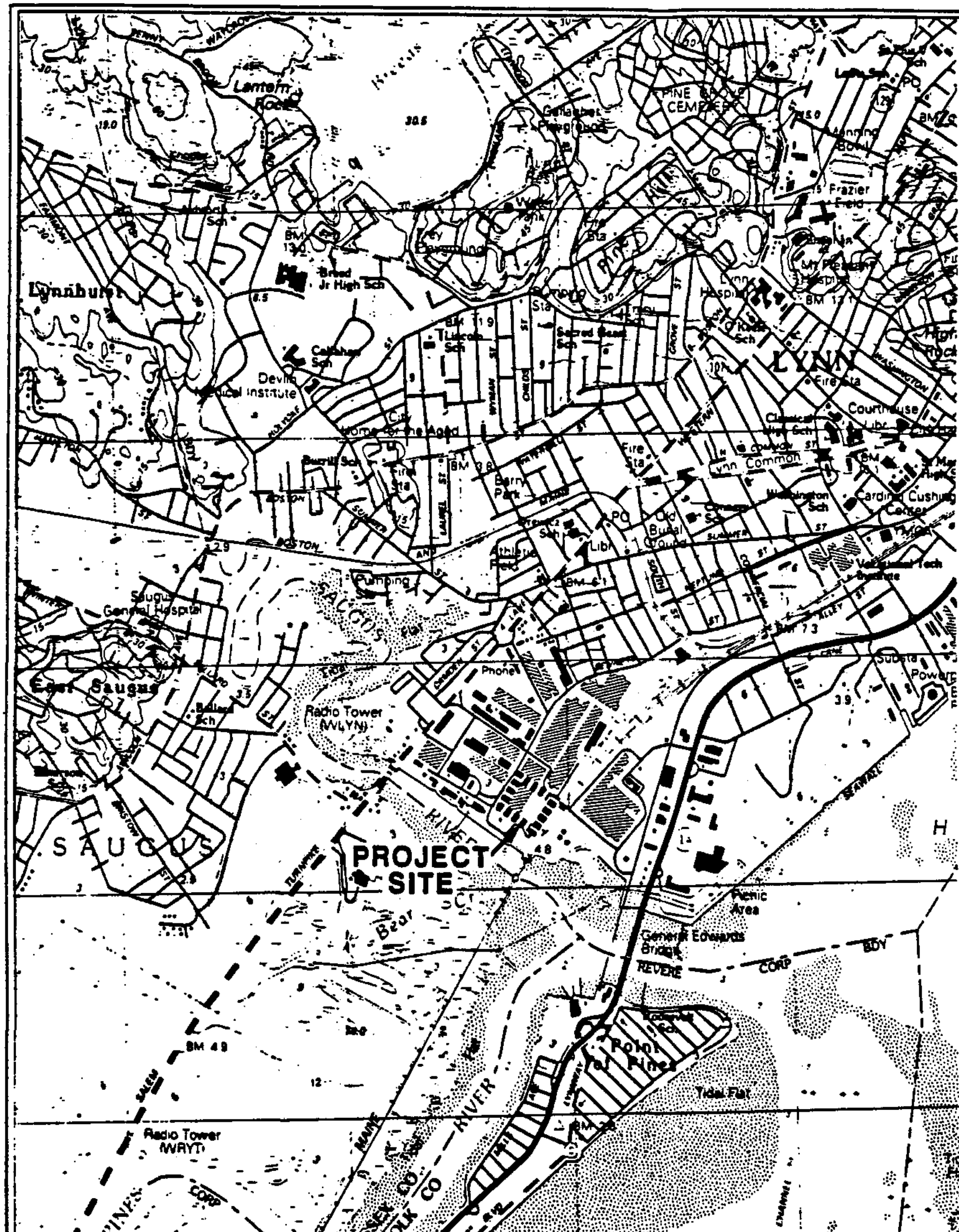
RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	**(1,544)**	**(912)**	**(566)**
Ref B	**(1,709)**	**(1,067)**	**(721)**
EndYr H	**(1,770)**	**(1,138)**	**(792)**
EndYr B	**(1,889)**	**(1,257)**	**(911)**
Ref L	**(1,954)**	**(1,322)**	**(976)**
Lin Regr	**(2,018)**	**(1,386)**	**(1,040)**
EndYr L	**(2,070)**	**(1,438)**	**(1,092)**
ExVal H	**(2,092)**	**(1,460)**	**(1,114)**
ExVal B	**(2,247)**	**(1,615)**	**(1,269)**
ExVal L	**(2,502)**	**(1,870)**	**(1,524)**
CGR Regr	**(2,835)**	**(2,203)**	**(1,857)**

NOTES: Table 6 incorporates changes from Table 5 comparable to those incorporated in Table 2 from Table 1. **Bold** signifies deficiency of at least 170 MW.

SOURCES: Exhs. Exhs. AL-40, attachs. RLC-8, RLC-9, RLC-14; HO-RR-61, at 1; JH-1, at 31.



SITE VICINITY MAP

Appeal as to matters of law from any final decision, order or ruling of the Siting Board 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 Board be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board 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 Board

In the Matter of the Petition of Cabot Power Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 91-101

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
March 9, 1994

On the Decision:

Phyllis Brawarsky
William Febiger
Dana Reed

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TABLE OF CONTENTS

The Energy Facilities Siting Board ("Siting Board") hereby approves subject to conditiions the petition of Cabot Power Corporation to construct a 235 megawatt bulk generating facility and ancillary facilities in Everett, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Cabot Power Corporation ("CPC" or "Company") has proposed to construct a 235 megawatt ("MW") natural gas-fired, combined-cycle[1] cogeneration facility on a 5.2-acre site, currently owned by MassGas, Inc., at the Island End Industrial Park ("IEIP") in the City of Everett, Massachusetts (Exh. CPC-1, at 1.1-1).

The proposed facility would be powered with natural gas provided by Distrigas of Massachusetts Corporation ("DOMAC") from its liquified natural gas ("LNG") marine terminal, a facility adjacent to the proposed project, with low-sulfur, distillate oil as a back-up fuel (id., at 1.4-1).[2] CPC has a contract for a 20-year, 365-day supply of natural gas from DOMAC. Under the terms of the contract, should vaporized LNG not be available for delivery, an equivalent volume of natural gas would be provided by DOMAC at no additional cost to CPC (id.). Natural gas deliveries would be arranged via existing pipeline/systems connected to the DOMAC LNG Terminal ("DOMAC Terminal") (id.). In the event that natural gas is unavailable, low-sulfur, light distillate oil would be used as a back-up fuel and will be piped directly to the proposed project from the Exxon Corporation marine terminal adjacent to DOMAC (id.; Exh. HO-PV-23). There would be no on-site

1 The Company noted that combined cycle refers to the production of electricity by both a fuel-fired combustion turbine-generator and a steam generator (Exh. CPC-1, at 3.3-1). The Company further noted that the steam turbine-generator is driven by steam generated from the waste heat of the combustion turbine exhaust (id.).

2 CPC, DOMAC and MassGas, Inc. are each wholly-owned subsidiaries of Cabot LNG Corporation (Exh. HO-B-2). Cabot LNG Corpæroation is in turn a wholly-owned subsidiary of Cabot Corporation, which has been in the energy business since 1882 (Exh. CPC-1, at 2.1-1, 2.2-1). CPC was incorporated in 1990 to develop, own and operate the proposed project (id.).

storage of fuel (Exh. CPC-1, at 3.3-6).

The electricity generated by the proposed facility would be transmitted via a 345 kilovolt underground cable to an existing substation at the nearby Boston Edison Mystic Station (id. at 3.3-5). CPC will sell thermal energy in the form of heated water to DOMAC for use in the vaporization of LNG for project consumption and delivery to DOMAC's other customers (id. at 2.2-1).

The major components of the proposed project consist of: (1) a 155 MW high-temperature combustion turbine-generator with dry low-NOx combusters; (2) a heat recovery steam generator ("HRSG"); (3) an 80 MW steam turbine generator; (4) a selective catalytic reduction ("SCR") system; (5) an air-cooled condenser; (6) a turbine air inlet chiller; and (7) a 240-foot exhaust stack (id. at 1.3-1, 3.3-4). Additional components include a 345 kV gas-insulated substation and an ammonia storage tank (id.). The Company stated that the power generation equipment, the combustion turbine-generator, heat recovery steam generator, steam turbine-generator, stack and associated equipment, would form an aisle down the middle of the site (id., at 3.3-3). Further, the combustion and steam generators would be housed within an existing building approximately 85 feet tall, and the heat recovery steam generator would be located out-of-doors (id.).

The Company's proposed site is located in an industrial park in a heavily industrialized area of Everett, Massachusetts (id. at 3.1-1). The proposed site is abutted by the DOMAC Terminal and an unused rail spur to the northwest and a warehouse to the northeast and is bordered by Rover and Commercial Streets to the southwest and southeast, respectively (id. at 3.1-1 and Fig. 3.3-2). Directly across Rover and Commercial Streets are a cement storage distribution facility and a sand and gravel operation (id. at 3.1-1).

The Company maintained that the proposed project would be consistent with various resource use and development policies of the Commonwealth (Exh. HO-CP-1). CPC argued that Massachusetts' energy policies: clearly favor cogeneration; support the view that demand-side management ("DSM") and cogeneration are complementary rather than mutually exclusive resources; and favor the increased use of natural gas as a means of diversifying the Commonwealth's energy supply (id.; and att. 1 - att. 3). In addition, CPC noted that the proposed project would be consistent with both economic and environmental policies of the Commonwealth by enhancing the productivity and competitiveness of an established Massachusetts manufacturing firm, and by minimizing air emissions and other environmental impacts through the use of natural gas as a primary fuel and the use of state-of-the-art generation and emission control equipment (id. and att. 1 - att. 4)).

The proposed project has been designated a Qualifying Facility ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") by the Federal Energy Regulatory Commission ("FERC") (Exh. HO-B-6 (att.)).

The proposed project would cost approximately $200 million in 1995 dollars (Exh. CPC-2, at 2.2-11).

B. Jurisdiction

CPC's petition to construct a bulk generating facility and ancillary facilities was filed in accordance with G.L. c. 164, §§ 69H and 69J, which require the Siting Board to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, §69J which requires electric companies to obtain Siting Board approval for construction of proposed facilities at a proposed site before a contruction permit may be issued by another state agency.

As a cogeneration facility with a design capacity of approximately 235 MW, CPC's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, §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, CPC's proposals to construct a transmission line and other structures at the site fall within the third definition of "facility" set forth in G.L. c. 164, §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.

C. Procedural History

On March 13, 1991, CPC filed with the Energy Facilities Siting Council ("Siting Council")[3] its proposal to construct a 235 MW natural gas-fired cogeneration facility and ancillary facilities in the City of Everett, Massachusetts. The Siting Council docketed this petition as EFSC 91-101. On July 9, 1991, the Siting Council conducted a public hearing in Everett. In accordance with the direction of the Hearing Officer, the Company provided notice of public hearing and adjudication.

Petitions to intervene were filed by the City of Everett, Altresco-Lynn, Inc., and a group of eleven residents from the Admiral's Hill Development in Chelsea. Petitions to participate as an interested person were filed by the Joseph L. DeAmbrose, ACS Development Corporation and the City of Chelsea .

On November 18, 1991, the Hearing Officer allowed all petitions to intervene and all petitions to participate as an interested person. See Hearing Officer Procedural Order, November 18, 1991 at 4-6. On November 25, 1991, the Hearing Officer conducted a pre-hearing conference at which procedural rules and discovery and hearing schedules were established.

The Siting Council initially conducted six days of evidentiary hearings commencing

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3 Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), the Siting Council was merged with the Department of Public Utilities ("Department" or "DPU") effective September 1, 1992. Reorganization Act, § 55. Petitions for approval to construct facilities that were pending before the Siting Council prior to September 1, 1992 were to be decided by the Siting Board, which is within, but not under the control or supervision of, the Department. Id., §§ 9, 15, 43, 46. The terms Siting Council and Siting Board will be used throughout this decision as appropriate to the circumstances being discussed.

The Reorganization Act provides that all facility petitions before the Siting Board, regardless of when they were filed, will be reviewed consistent with all orders, rules and regulations duly made, all approvals duly granted, and all legal and decisional precedents established by the Siting Council until superseded, revised, rescinded, or cancelled in accordance with law by the Siting Board. Id., § 46.

June 1, 1992 and ending June 26, 1992. CPC presented seven witnesses: David Keast, an acoustical consultant and subcontractor to HMM Associates, Inc. ("HMM"), who testified regarding issues related to noise; Douglas S. Jones, a consultant with CPC, who testified regarding environmental permitting/licensing, site development and selection, water supply, land use and zoming, traffic, visual impacts, water discharge, alternative cooling technologies, and wetlands and site conditions; Joseph A. Teves, president of DOMAC, who testified regarding fuel supply; William Groot of HMM, who testified regarding environmental permitting and environmental impacts; Peter J. Thalman, a principal with PLM, Inc., who testified regarding transmission interconnection issues; Richard La Capra, utility analyst and principal of La Capra Associates, who testified on the need for, and the Massachusetts benefits of, the proposed project; and A. Edwin Toombs, the CPC project manager for the proposed project, who testified regarding the development of the project, comparisons with alternatives, viability, costs, construction and safety. None of the intervenors presented witnesses.

The Company filed its brief ("Company Brief") on August 17, 1992. None of the intervenors or interested persons filed a brief.

On September 4, 1992, CPC submitted a letter ("Company Letter") to the Siting Council responding to the Supreme Judicial Court's Decision in City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"). In City of New Bedford, the Court remanded the conditional approval of a proposed generating facility to the Siting Council "to compare alternative energy resources" in its review of the proposed project.[4] Id. at 484.

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4 In City of New Bedford, the Court also identified four other issues for reconsideration:

> (1) Because the Siting Council's mandate referred to a necessary energy supply for the Commonwealth, the Siting Council's finding that additional energy resources are needed for New England was inadequate;
> (2) The Siting Council must make a finding that the proposed project would produce power at the lowest possible cost;

(continued...)

In light of the Court's directive that such a comparison is a necessary element of a Siting Board review of a proposed project, the Company argued that the Siting Board had available to it the evidence necessary to rule on CPC's petition consistent with that directive (Company Letter at 1-2). Nevertheless, the Company proposed that all parties be permitted to submit supplemental briefs to address the CPC proceeding in light of the Court's decision in City of New Bedford (id. at 3).

On October 30, 1992, the Hearing Officer issued a Memorandum requesting the Company to provide certain updated information and some additional information and providing for a further reopening of the record. The Company submitted supplemental testimony and exhibits on November 13, 1993. Three additional days of hearings were held between January 17, 1993 and January 24, 1993 on this additional information. CPC presented three witnesses who had testified in the earlier proceedings: Douglas S. Jones and A. Edwin Toombs, both of whom testified regarding alternative energy technologies, and Richard La Capra, who testified regarding alternative energy technologies and the Massachusetts need for the proposed project. CPC presented one additional witness, Robert M. Graham, an analyst for La Capra Associates, who also testified regarding alternative energy technologies and the Massachusetts need for the proposed project. The Company filed its Supplemental Initial Brief on March 15, 1993, which addressed the comparison of the proposed project to alternative energy approaches and the Massachusetts need for the proposed project ("Company Supplemental Brief").

The Hearing Officer entered 347 exhibits into the record, consisting primarily of information and record request responses. CPC entered 21 exhibits into the record. The Residents entered 21 exhibits into the record.

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[4](...continued)

> (3) The Siting Council must determine that the proposed project would provide a "necessary" energy supply; and
> (4) The final decision must be "accompanied by a statement of reasons . . . including determination of each issue of fact or law necessary to the decision."

413 Mass at 489-490.

D. Scope of Review

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct facilities, the Siting Board requires applicants to justify generating facility proposals in four phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. Altresco Lynn, Inc., EFSB 91-102 at 10 (1993) ("Altresco Lynn Decision"); Eastern Energy Corporation (on Remand), EFSB 90-100R at 190 (1993) ("EEC (remand) Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA Decision") (see Section II.A. below). Second, the Siting Board requires the applicant to show that, on balance its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability.[5] Altresco Lynn Decision, EFSB 91-102 at 10; EEC (remand) Decision, EFSB 90-100R at 65; NEA Decision, 16 DOMSC at 364 (see Section II.B., below). Third, the Siting Board requires the applicant to show that its project is viable. Altresco Lynn Decision, EFSB 91-102 at 11; Boston Edison Company, EFSB 90-12/90-12A at 15 (1993) ("1993 BECo Decision"); NEA Decision, 16 DOMSC at 364 (see Section II.C., below). Finally, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and (1) in cases where an alternative site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply, or (2) in cases where a noticed alternative is not required, that the proposed site for the facility will minimize environmental impacts and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply. Altresco Lynn Decision, EFSB 91-102 at 11; 1993 BECo Decision, EFSB 90-12/90-12A at 15, 32; Eastern Energy Corporation, 22 DOMSC 188, 315-316 (1991)("EEC Decision"); NEA Decision, 16 DOMSC at 343 (see Section III, below).

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5 In City of New Bedford, supra, the Court stated that this standard of review, which was applied by the Siting Council up to 1990, comports with its statutory mandate. 413 Mass. at 485.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

a. The Company's Position

The Company argued that, consistent with the statutory mandate and the Court's decision in City of New Bedford, there are two reasonable approaches for the Siting Board to use to determine whether the proposed facility is needed based on reliability considerations -- a demonstration of a capacity deficiency for Massachusetts or a demonstration of a capacity deficiency on a regional basis (Company Supplemental Brief at 7-8). The Company asserted that, where a capacity deficiency is demonstrated for Massachusetts based on an analysis of the projected electricity demand within the Commonwealth and the supply resources committed to meet that demand, the clear language of the statute would require the Siting Board to find that a proposed facility is needed to provide a necessary energy supply for the Commonwealth (id.).

In the alternative, the Company asserted that the Siting Board can find need for a proposed facility where a deficiency is demonstrated on a regional basis, provided that the Siting Board provides a statement of reasons why a finding of regional need meets the statutory requirements (id. at 8). CPC stated that, given the integrated regional electricity system and tangible benefits to Massachusetts resulting from participation in the New England Power Pool ("NEPOOL") system, it would be consistent with the statute to base need for a proposed facility on regional considerations (id. at 8-12).[6]

In addition, the Company stated that, although the Court was silent on the

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[6] The Company asserted that the inextricable link between regional and Massachusetts' reliability and the appropriateness of a regional need analysis was recognized by the Legislature in establishing the Siting Council (Company Supplemental Brief at 8-9). The Company asserted that the appropriateness of a regional analysis was also confirmed by G.L. c. 164A, the intent of which is to foster participation of electric utilities in NEPOOL (id. at 10).

appropriateness of using economic efficiency[7] as an independent basis to demonstrate need, an economic efficiency analysis also would be consistent with the Siting Board's obligation to ensure a necessary energy supply at the lowest possible cost with a minimum impact on the environment (id. at 12). Therefore, the Company asserted that a demonstration that a proposed facility would result in lower costs for the Commonwealth's ratepayers would be sufficient to establish need (id.). The Company further asserted that a regional economic efficiency analysis also would demonstrate Massachusetts' economic efficiency benefits (id. at 13). The Company explained that due to the integrated nature of the NEPOOL system, Massachusetts would share in the economic efficiency savings of a facility, even if the power were sold to a utility outside Massachusetts (id.).

Finally, the Company asserted that regional economic efficiency-based need should be expanded to allow for the determination of need based on a demonstration that the addition of the proposed facility would reduce environmental impacts associated with the generation of electricity to a greater extent than any reductions that would take place without the facility (id. at n.7).

b. Analysis

In the EEC (remand) Decision, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with the statutory mandate to implement

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7 The Company noted that in Enron Power Enterprise, 23 DOMSC (1991) ("Enron Decision") the Siting Council found that economic efficiency can establish need if the addition of the proposed new facility would result in lower generation costs for the system than would be experienced without the new facility (Company Supplemental Brief at 12).

The Siting Board notes that in the Enron Decision, the Siting Council found that the facility was needed for economic efficiency purposes in addition to reliability purposes. 23 DOMSC at 63-65. The Siting Council made it clear that it would have to evaluate, on a case-by-case basis, whether the magnitude and timing of the economic efficiency gains identified would be adequate to establish need solely on economic efficiency grounds. Id., 23 DOMSC at 59-60. See also, Altresco Lynn Decision, EFSB 91-102, at 58-61.

the energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost and the Court's directive in City of New Bedford.

In City of New Bedford, the Court found the Siting Council's finding that New England needed additional energy resources for reliability purposes to be inadequate in light of the statutory mandate that an energy supply must be necessary for the Commonwealth. 413 Mass. at 489. In addition, the Court noted that, although the Siting Council had argued that its mandate was to ensure an adequate energy supply at minimum cost, "[e]nsuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth' (emphasis added)." Id., 413 Mass. at 490, citing, G.L. c. 164, § 69H.

With respect to the issue of regional need vs. Massachusetts need, in the EEC (remand) Decision, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability. The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration. Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not yet linked to individual utilities by power purchase agreements ("PPAs"). See, EEC (remand) Decision, EFSB 90-100R at 185. The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3,4. Accordingly, the Siting Board has found that an analysis of regional need must form the foundation for an analysis of Massachusetts need. Id. at 186.

The Company argued that a showing of either a Massachusetts capacity deficiency or a regional capacity deficiency should be sufficient, on its own, to establish need for a proposed facility. As stated above, however, the Siting Board has recognized in past reviews that a regional capacity analysis provides a necessary foundation for, rather than the sole determinant of, a finding of need.[8] Id. at 188; Altresco Lynn Decision, EFSB 91-102, at 17. Therefore, neither a regional capacity deficiency, taken alone, nor a Massachusetts capacity deficiency, taken alone, would be sufficient to establish need. Id.

Finally, with respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board agrees with the Company that such analyses of need would be consistent with our statutory obligation 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, §§ 69H, 69J. The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. Altresco Lynn Decision, EFSB 91-102, at 58-61; EEC (remand) Decision, EFSB 90-100R at 186-187. However, in response to the Court's reminder in City of New Bedford that our statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need. EFSB 90-100R at 187.

After considering the arguments presented by the Company, the Siting Board finds that the standard of review for the determination of need established in the EEC (remand) Decision continues to be appropriate. That standard is set forth below.

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8 The Siting Board has also found that demonstration of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply. See, EEC (remand) Decision, EFSB 90-100R at 188. The Siting Board noted that an applicant could establish that reliance on a regional surplus to address or offset a Massachusetts supply deficiency could involve transmission or other reliability constraints or could be contrary to the statutory mandate to ensure that a necessary energy supply is provided for the Commonwealth at the lowest possible cost with least environmental impact. Id.

c. Conclusion

In accordance with G.L. c. 164, § 69H, the Siting Board 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. The Siting Board, therefore, must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities. With respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources to meet reliability, economic, or environmental objectives directly related to the energy supply of the Commonwealth.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate 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 Board 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. Altresco Lynn Decision, EFSB 91-102, at 19; EEC (remand) Decision, EFSB 90-100R at 190-191; Altresco-Pittsfield, Inc., 17 DOMSC 351, 360-369 (1988) ("Altresco-Pittsfield Decision; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988); Boston Edison Company, 13 DOMSC 63, 70-73 (1985) ("1985 BECo Decision"); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. Altresco Lynn Decision, EFSB 91-102, at 19; EEC (remand) Decision, EFSB 90-100R at 191.

While G.L. c. 164, § 69H, requires the Siting Board to ensure a necessary supply of energy for Massachusetts, the Siting Board interprets this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources,[9] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Altresco Lynn Decision, EFSB 91-102, at 19; EEC (remand) Decision, EFSB 90-100R at 191; Massachusetts Electric Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985). In doing so, the Siting Board fulfills the requirements of G.L. c. 164, § 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.

Thus, in cases where a non-utility developer seeks to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board requires the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. MASSPOWER, Inc., 21 DOMSC 196, 200 (1990); MASSPOWER, Inc., 20 DOMSC 1, 19-23, 32 (1990) ("MASSPOWER Decision"); Altresco-Pittsfield Decision, 17 DOMSC at 366-367. 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, the need for additional energy resources must be established through an analysis of regional capacity and a showing of Massachusetts need based either on reliability, economic or environmental grounds directly related to the energy supply of the Commonwealth. Altresco Lynn Decision, EFSB 91-102, at 20; EEC (remand) Decision, EFSB 90-100R at 192; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision").

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9 See, Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985); 1985 BECo Decision, 13 DOMSC at 70-73.

2. Power Sales

In the NEA Decision, 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 a 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 for the need for additional energy resources for reliability purposes. Id. Here, the record provides no indication that any of the project output has been sold.

Accordingly, based on the foregoing, the Siting Board finds that CPC has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPAs. Therefore, the Siting Board reviews the Company's analyses of regional and Massachusetts need to determine whether the proposed project is needed to provide necessary energy to the Commonwealth.

3. New England's Need

a. Introduction

CPC asserted that there is a need for 235 MW of additional energy resources in New England beginning in 1996 and beyond (Company Brief at 10, citing, Tr. 5, at 12). In support, the Company (1) presented a series of forecasts of demand and supply for the region, based, in part, on data and 1992 forecasts published by NEPOOL, and (2) combined its demand and supply forecasts to produce a series of need forecasts (Exh. CPC-9).[10] CPC

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[10] CPC originally provided an analysis of regional need based, in part, on load forecast data contained in the NEPOOL Forecast of Capacity, Energy, Loads and Transmission ("CELT Report") 1990-2005 ("1990 CELT Report") (Exhs. CPC-1, sec. 4; CPC-11). In its original analysis, the Company subjected its need forecasts to a variety of contingency tests to evaluate the sensitivity of the need projections to the uncertainty inherent in the underlying forecast assumptions (id. at 4.2-10 to 4.2-13).

(continued...)

asserted that it provided a comprehensive analysis of the need for the proposed facility, consistent with Siting Council standards (Company Brief at 11).

CPC also presented an analysis of regional need based on economic efficiency grounds (Exhs. CPC-9, at 32-37, exh. RLC(35a), exh. RLC(35b); HO-N-36; HO-RR-22; HO-RR-23). The Company asserted that this analysis establishes need for the project on economic efficiency grounds (Company Brief at 55).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts, which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the Company's analysis of economic efficiency need.

b. Demand Forecasts

CPC presented eleven demand forecasts of adjusted peak load demand (Exh. CPC-9). The Company stated that it based its demand forecasts on seven different demand forecast methodologies and two different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 1-21, 26-27). To derive its eleven demand forecasts, the Company indicated that it adjusted results from four of its forecast methodologies to reflect the two respective DSM forecasts, generating eight demand forecasts, and utilized the results from the remaining three forecast methodologies without separate reductions to reflect DSM (id., exh. RLC(26)).

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[10](...continued)

The Company updated its analysis of regional need after the publication of the CELT Report 1992-2007 ("1992 CELT Report") (Exh. CPC-9). In its updated analysis of regional need, the Company did not provide an updated analysis of the contingency scenarios (id.).

i. Description of Demand Forecast Methodologies

The Company stated that four of its demand forecasts were based on load forecast data contained in the 1992 CELT Report and the three additional demand forecasts were based on historical trends (id. at 1-21).[11] With respect to the four 1992 CELT Report-based forecasts, CPC noted that the 1992 CELT Report contains three distinct forecasts of regional load -- a high demand forecast, a reference forecast, and a low demand forecast (id. at 2-4).[12] The Company stated that it utilized the 1992 CELT reference forecast ("reference forecast") and the 1992 CELT high demand forecast ("high demand forecast") directly[13] and based two additional forecasts on variations of the 1992 CELT Report forecasts, including (1) the arithmetic average of the 1992 CELT Report high and low demand cases ("high-low average forecast"), and (2) a linear projection between 1992, or first year, reference forecast peak load and 2007, or end-year, reference forecast peak load ("end-year linear forecast") (id. at 1-21, 30-31). As noted above, each of these four demand forecasts was adjusted by each of the two DSM forecasts to generate eight final forecasts for use in the development of the need forecasts.

With respect to the forecasts based on historical trends, the Company stated that it developed three forecasts as follows: (1) a historical time series constant annual growth rate ("CAGR") regression forecast, based on projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("CAGR regression forecast"); (2) a historical time series

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11 In its updated regional need analysis, the Company included an analysis of need based on the 1990 and the 1991 CELT Report (1991-2006) ("1991 CELT") for illustrative purposes but not for the purpose of evaluating regional need (Exh. CPC-9, n.11). For purposes of this review, the Siting Board does not consider the 1990 or 1991 CELT Report or associated need analyses in the analysis of need for the proposed facility.

12 CPC indicated that NEPOOL characterizes: (1) the high demand case as having a 10 percent probability of being exceeded; (2) the reference case as having a fifty percent probability of being exceeded; and (3) the low demand case as having a 90 percent probability of being exceeded (Exh. CPC-9, n.1).

13 CPC stated that the 1992 CELT Report low demand forecast was presented for illustrative purposes only (Exh. CPC-9, n.11).

linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("linear regression forecast");[14] and (3) a multiple regression forecast based on the 1974-1989 multiple regression relationship of personal income and time to peak load, and a forecast of personal income ("multiple regression forecast") (id. at 14-21).[15]

The Company indicated that three of the seven forecast methodologies -- the reference forecast, the CAGR regression forecast, and the linear regression forecast -- are common to both the regional need analysis and the Massachusetts need analysis (Exh. JH-RR-7; Tr. JH2, at 49-51).

The Company asserted that the high-low average forecast, the end-year linear forecast, the CAGR regression forecast, the linear regression forecast, and the multiple regression forecast reflected reliable methodologies to forecast the regional demand for power (Company Brief at 13-19). However, the Company stated that it considered the high-low average forecast to represent a principal demand forecast and the end-year linear forecast to represent a conservative but reasonable alternative (Exh. CPC-9, at 21).[16]

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14 The Company noted that the CAGR regression forecast and linear regression forecast were updated to reflect 1992 CELT Report data (Exh. CPC-9, at 2).

15 The Company indicated that the forecast of personal income for the years 1990-2014 was based on a forecast for Massachusetts from the Massachusetts Division of Energy Resources ("DOER") which in turn was based on a forecast produced by Regional Economic Models Inc. ("REMI") (Exh. CPC-9, at 18). The Company further indicated that the DOER forecast extended only through 1996 and that the forecast was extended through 2007 by assuming a CAGR for the 1997-2007 period equal to the CAGR for the 1992-1996 period that was included in the DOER forecast (id.).

16 Mr. La Capra indicated that both the high-low average forecast and end-year linear forecast meet the criterion established by the Siting Council in the Enron Decision and the EEC Decision that a principal demand forecast be based on a sophisticated methodology (Exh. CPC-9, at 19-21).

(A) 1992 CELT Report Forecasts

As noted above, the 1992 CELT Report contains a high demand forecast, a reference forecast, and a low demand forecast (id., n.1). With respect to the reference forecast, CPC asserted that such a forecast was not appropriate, without adjustment, for use as a principal forecast in the regional need analysis (Company Brief at 20). Rather, CPC characterized the reference forecast as a reasonable low demand case (Exh. CPC-9, at 7). In explaining NEPOOL development of the reference forecast, the Company provided the NEPOOL Forecast of New England Electric Energy and Peak Load Executive Summary 1992-2007 ("Executive Summary") which indicated that NEPOOL produced (1) a short-term forecast for the years 1992 and 1993 based on an econometric model of three exogenous variables -- personal income, number of residential customers, and real energy prices, and (2) a long-term forecast for the years 1996 through 2007 based on an end-use model (Exh. HO-RR-17(a) at 2-1). The Executive Summary indicated that NEPOOL then merged the short-term and long-term forecasts to produce projections for the years 1994 and 1995 and that, in moving from the short-term to the long-term, "the forecast was adjusted to approach the long-run results smoothly over a two-year interim period" (id.).

CPC stated that the reference forecast reflects a CAGR in adjusted peak load of only 0.56 percent over the 1992-1995 period[17] and projects that adjusted peak load will be lower than NEPOOL's 1991 weather-normalized summer peak of 19,700 MW until the year 1994 (id. at 3, 8).[18] The Company asserted that the New England region is currently

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[17] The Siting Board notes that the reference forecast annual growth in load for the period 1991-2000 is as follows: (1) 1992, -1.06 percent; (2) 1993, 0.51 percent; (3) 1994, 1.44 percent; (4) 1995, 1.39 percent; (5) 1996, 2.52 percent; (6) 1997, 1.4 percent; (7) 1998, 2.7 percent; (8) 1999, 2.8 percent; and (9) 2000, 1.96 percent (Exh. HO-RR-15, at 1).

[18] Mr. La Capra indicated that the reference forecast, adjusted by the 1992 CELT values for DSM reflects a CAGR in adjusted peak load of: (1) 1.9 percent over the 1991-2007 forecast period; (2) 0.56 over the 1991-1995 period; (3) 2.3 percent over the 1995-2000 period; and (4) 2.4 percent over the 2000-2007 period (Exh. CPC-9, at 3). Mr. La Capra noted that the CAGR of the adjusted reference forecast is nearly equal to that of the adjusted high demand forecast over the 2000-2007 period (id. at 3-4).

experiencing an economic recovery and that the lack of short-term growth in peak demand projected by the reference forecast is inconsistent with the region's historical experience in emerging from recessions (Company Brief at 34; Exh. HO-RR-13).[19]

Mr. La Capra maintained that the downward bias of the short-run results of the reference forecast is primarily due to (1) overly pessimistic economic assumptions which underlie the personal income forecast, and (2) unrealistically high fuel price projections which are the primary drivers of real electricity prices (Exhs. CPC-9, at 11 to 13; CPC-17 at 4-9; Tr. 5 at 52-54). In forecasting the variables underlying the short-term forecast, Mr. La Capra explained that NEPOOL relied on a modified Delphi method, or opinion poll of members of its Load Forecasting Committee (Exhs. HO-RR-17(a) at 2-1; CPC-17, at 8). He noted that NEPOOL adjusted the personal income forecast for 1992 downward from an objective forecast of personal income in order to lower the short-term forecast (Exh. CPC-17, at 74-78).[20] He also noted that NEPOOL made upward adjustments to an objective forecast of residual oil and natural gas fuel price escalators (Exh. HO-RR-14(a)).[21,22]

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19 CPC stated that NEPOOL's short-term forecast assumes recovery would not begin until the fourth quarter of 1992 whereas recent economic indicators demonstrate that the region's recovery began in the first quarter of 1992 (Exhs. HO-RR-15; CPC-17, at 4).

20 Mr. La Capra indicated that the "NEPOOL Economic and Demographic Forecast, New England and the Six States, 1992-2007" ("1992 Economic and Demographic Forecast") specifies an increase in real personal income of 1.9 percent in 1991 and 2.2 percent in 1992 whereas a zero percentage increase for 1991 was assumed by NEPOOL in the short-term forecast (Exhs. HO-RR-19, at 13; CPC-17, at 77). The 1992 Economic and Demographic Forecast was the sum of the six state forecasts which in turn were based on the New England Power Planning Committee ("NEPLAN") state-specific economic models developed from REMI state models and the 1991 Data Resources Inc. ("DRI") national economic forecast (Exh. HO-RR-19, at 1).

21 Mr. La Capra indicated that the NEPOOL fuel price forecast was derived from the draft December 1991 NEPOOL "Summary of the Generation Task Force Long-Range Study Assumptions" ("GTF") which, in turn, was based on an October 1991 DRI (continued...)

The Company asserted that, although the methodological flaws in the reference forecast pertain largely to the short-term forecast, the short-term forecast directly impacts the growth in demand projected by the long-term forecast for the year 1996 and beyond (Company Brief at 28-34; Tr. 5 at 43-44, 54). Mr. La Capra explained that the short-term forecast causes the long-term forecast to begin from a lower base and, therefore, produces a significantly lower forecast of peak load (Exh. CPC-17, at 71).[23] The Company asserted that further evidence of the influence of the short-term forecast on the long-term forecast is the dramatic difference in the slope of the forecast for the 1991-1995 period (0.56 percent)

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[21](...continued)
energy forecast ("1991 DRI forecast") (Exh. HO-RR-14(a)). However, he noted that the residual oil and natural gas price escalators used by NEPOOL for the 1992-1994 period were significantly higher than the comparable fuel price escalators included in the 1991 DRI forecast (id.). Further, Mr. La Capra noted that the fuel prices included in the 1992 GTF, with the exception of nuclear fuel, were lower than those prices projected by NEPOOL in the 1992 CELT Report (id.).

[22] In order to approximate the impacts that a change in NEPOOL's fuel price would have on its projections of regional demand, the Company provided alternative forecasts based on lower fuel price assumptions included in (1) the 1992 GTF, and (2) the May 1991 forecast of fuel prices prepared for a New England utility (Exh. HO-RR-14). The Company provided an additional demand forecast based on the United States Department of Energy ("DOE") annual electricity sales projections for New England (id.). The Company stated that all three forecasts would show need for the proposed project earlier than the reference forecast (id.).

[23] The Company further explained that because NEPOOL fuel price forecasts are expressed as annual escalation rates rather than absolute dollar values, the effects of the fuel price escalators assumed by NEPOOL for 1992 continue through the forecast period and are compounded by the high price elasticity assumed by NEPOOL (Exh. HO-RR-14(a)). The Company asserted that the annual escalation rates would cause the long-run demand forecast to begin from a lower base point because the annual fuel price escalation rates are applied to a base value, specifically the fuel price in the 1995 forecast, which is greatly influenced by the short-term forecast (Company Brief at 29; Exh. CPC-17, at 70-71).

and 1995-2000 period (2.29 percent) (Company Brief at 29).[24]

In sum, the Company asserted that the reference forecast should be rejected for the same reasons that the Siting Council previously rejected the 1991 CELT forecast -- inconsistency with historical trends, overly pessimistic economic assumptions and inflated oil prices (Company Initial Brief at 34-38).[25]

With respect to the high demand forecast in the 1992 CELT Report, Mr. La Capra characterized it as a reasonable high demand case included in the Company's analysis of regional need (Exh. CPC-9, at 7, n.11, exh. RLC(32)). He indicated that the high demand forecast anticipates a spurt in the demand for electricity based on a strong recovery of the regional economy and sustained strong growth in peak demand throughout the forecast period (id. at 7,8).[26] He stated that, although such economic assumptions would be consistent with the region's repeated pattern of higher than average recovery from a recessionary period, he considered the magnitude of the projected growth spurt and CAGR over the forecast period to be optimistic (id.; Exh. CPC-15, at 103).

Mr. La Capra indicated that the low demand forecast in the 1992 CELT Report predicts a significant decline in peak demand in 1992, remaining below the NEPOOL 1991 weather-normalized summer peak until the year 2000 (Exh. CPC-9, at 8,9). He stated that such a decline in peak demand is unprecedented and unsupported by evidence that an

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24 The Company asserted that, assuming the 1996 forecast was produced solely by the long-run model, the long-run model would, therefore, have independently forecasted the same 0.56 percent growth rate for the 1991-1995 period, contradicting economic assumptions underlying the forecast (Company Brief at 29-30, citing, Exh. HO-RR-19). In addition, the Company asserted that there is no evidence of a sufficiently large adjustment in the years 1994 and 1995 to bridge the gap between the load growth slopes of 0.56 percent and 2.29 percent (id. at 31).

25 See Enron Decision, 23 DOMSC at 42-43; EEC Decision, 22 DOMSC at 235-236.

26 Mr. La Capra indicated that the high demand forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 3.4 percent over the 1991-2007 forecast period; (2) 5.0 percent over the 1991-1995 period; (3) 3.5 percent over the 1995-2000 period; and (4) 2.5 percent over the 2000-2007 period (Exh. CPC-9, at 2-3).

economic recovery is currently underway (id.). He, therefore, characterized the low demand forecast as having a probability of occurrence of essentially zero and stated that it should not be considered in the analysis of regional need (id.).

(B) High-Low Average Forecast

As noted above, the Company indicated that the high-low average forecast, the arithmetic average of the low demand forecast and the high demand forecast from the 1992 CELT Report, represents its principal forecast.[27] Given that the reference forecast is significantly closer to the low demand forecast than the high demand forecast, Mr. La Capra indicated that the high-low average forecast would better represent the range of forecasts embodied in the 1992 CELT Report than would the reference forecast (Exh. CPC-9, at 17).[28] However, he added that, in assuming equal probability for the low demand forecast and high demand forecast, the high-low average forecast constitutes a conservative projection of future load growth (Exh. HO-RR-9).[29] He noted that the high-low average forecast shows stronger growth in the early years relative to the reference forecast (Exh. CPC-15, at 65).

The Company asserted that the 1992 NEPOOL Resource Adequacy Assessment, Technical Supplement ("1992 Resource Assessment") confirms that the high-low average forecast is a reasonable forecast (Company Initial Brief at 39, citing, Exh. HO-RR-16). The

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27 Mr. La Capra indicated that the high-low average forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 2.15 percent over the 1991-2007 forecast period; (2) 2.12 percent over the 1991-1995 period; (3) 2.37 percent over the 1995-2000 period and (4) 2.01 percent over the 2000-2007 period (Exh. CPC-9, at exh. RLC(19)).

28 The Company stated that this asymmetry means there is a greater likelihood of the reference forecast underforecasting than overforecasting demand by a given margin (Exh. CPC-9, at 17).

29 As noted above, the Company considers the high demand forecast to be a reasonable high demand case while it considers the low demand forecast to have a probability of occurrence of essentially zero (Exh. CPC-9, at 7).

Resource Assessment provides a probability distribution for the variation in expected regional load growth assumed by NEPOOL for the years 1993 through 1997 (Exh. HO-RR-16). From this distribution, the 1992 Resource Assessment provides the expected value, or weighted average of all possible outcomes in the distribution, of the load forecast for each year from 1993 though 1997 (id.). The Company asserted that the expected value of the 1997 capacity position is consistent with the 1997 capacity position projected by the high-low average forecast (Company Brief at 39; Tr. JH-1, at 17).[30] The Company further asserted that the Resource Assessment demonstrates that the uncertainty associated with load growth, existing utility attrition, DSM and other factors is more likely to result in a capacity shortfall than a capacity surplus if NEPOOL plans its resources to meet the reference forecast (Company Initial Brief at 39, citing, Tr. 5, at 14-15).

(C) End-Year Linear Forecast

With respect to the end-year linear forecast, the Company explained that this forecast assumes that the beginning and end points of the reference forecast are correct and that peak load will grow linearly between these two points (Exh. CPC-9, at 16). The Company stated that, therefore, the end-year linear forecast partially corrects for the unreasonable assumptions underlying short-term growth in the reference forecast (id.).[31] The Company noted that, in reflecting the same long-term increase as the reference forecast -- 1.9 percent per year between 1992 and 2007 -- the end-year linear forecast is reasonable but conservative

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30 The Company indicated that the expected value in 1997 is a capacity deficiency of 241 MW (Exh. HO-RR-77). The Siting Board notes that, assuming the Company's base supply forecast, the high-low average forecast projects a 1997 capacity deficiency ranging from 961 MW to 1,356 MW, under two alternative DSM forecasts (Exh. CPC-9, at exh. RLC-26).

31 Mr. La Capra indicated that the end-year linear forecast, adjusted by the 1992 CELT Report values for DSM, reflects a CAGR in adjusted peak load of: (1) 1.90 percent over the 1997-2007 forecast period; (2) 2.13 over the 1991-1995 period; (3) 1.95 percent over the 1995-2000 period; and (4) 1.74 percent over the 2000-2007 period (Exh. CPC-9, at exh. RLC(19)).

relative to other forecasts based on the region's long-term trends (id. at 16-17).[32]

(D) Forecasts Based on Historical Trends

As noted above, the Company provided three additional demand forecasts based on historical trends -- the CAGR regression forecast, the linear regression forecast and the multiple regression forecast. The Company stated that it developed the CAGR regression forecast and linear regression forecast based on performing time series regression analysis of 1974-1991 weather-normalized summer peak load data for New England derived from NEPOOL data (id. at 14-15; Exh. CPC-11). The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the CAGR and linear regression equations, and claimed that a moderate-to-high amount of DSM thus was incorporated in these regression forecasts (Exh. HO-MN-25).[33] The Company stated that the projected growth in peak load would be 2.93 percent per year under the CAGR regression forecast and 468 MW per year under the linear regression forecast (Exh. CPC-9, at exh. RLC(19), exh. RLC(20b).[34] The Company stated that, although both the CAGR and linear regression formats exhibit statistically solid results, the CAGR regression forecast

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32 The Company indicated that the projected growth in peak load would be 433.6 MW per year under the end-year linear forecast (Exh. HO-RR-9).

33 The Company stated that the CAGR and linear regression forecasts reflect a continuation of a rapid rate of increase in DSM resources over the historical period and that the rate of growth in DSM resources is likely to decline over time as cost-effective DSM opportunities decline (Exh. HO-MN-25). Therefore, the Company stated that the DSM included in the regression forecasts is likely to be accurate in the short-run but too high in the long-run (id.).

34 Mr. La Capra indicated that the linear regression forecast, reflects a CAGR in adjusted peak load of: (1) 2.00 percent over the 1991-2007 forecast period; (2) 2.25 percent over the 1991-1995 period; (3) 2.05 percent over the 1995-2000 period; and (4) 1.82 percent over the 2000-2007 period (Exh. CPC-9, at exh. RLC(19)).

is statistically superior (id. at 15).[35]

The Company stated that it developed the multiple regression forecast using personal income and time as independent variables (id. at 19).[36,37] Mr. La Capra acknowledged that the confidence in this forecast methodology depends on the forecast of personal income and stated that the forecast of personal income utilized in developing the multiple regression forecast was a reasonable projection of personal income (Exh. CPC-16, at 106-108). Mr. La Capra asserted that, absent major structural changes in the economy such that increases in disposable income and commercial activity would not require increases in energy use, the multiple regression forecast would be a reliable predictor of electric demand over the long-term (Exh.id. at 102-106).

ii. Analysis

As noted above, the Company presented two demand forecasts included in the 1992 CELT report (the reference forecast and the high demand forecast), developed two additional demand forecasts based on the load forecast data contained in the 1992 CELT report (the end-year linear forecast and the high-low average forecast) and developed three additional demand forecasts based on historical trends (the linear regression forecast, the CAGR regression forecast and the multiple regression forecast). The Siting Board analyzes each of these forecasts in the sections below.

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35 The Company noted that the use of a CAGR regression was accepted by the Siting Council in the Enron Decision, the EEC Decision, and the West Lynn Decision (Company Supplemental Brief at 23).

36 Mr. La Capra indicated that a series of single and multiple regression analyses of three independent variables -- time, Massachusetts personal income and Massachusetts state product -- demonstrated that the regression on personal income and time exhibited the best overall statistical results (Exh. CPC-9, at 18-19).

37 Mr. La Capra indicated that the multiple regression forecast reflects a CAGR in adjusted peak load of: (1) 3.00 percent over the 1991-2007 forecast period; (2) 2.96 percent over the 1991-1995 period; (3) 3.00 percent over the 1995-2000 period; and (4) 3.03 percent over the 2000-2007 period (Exh. CPC-9, at exh. RLC(19)).

(A) Reference Forecast and High Demand Forecast

With respect to the reference forecast, the Siting Board notes that the CELT report has previously been acknowledged as an appropriate starting point for resource planning in New England and CELT forecasts have previously been accepted for the purposes of evaluating regional need in reviews of proposed non-utility generator ("NUG") facilities. See, e.g., Altresco Lynn Decision, EFSB 91-102, at 36; EEC (remand) Decision, EFSB 90-100R at 211; EEC Decision, 22 DOMSC 234-236; NEA Decision, 16 DOMSC at 354. Specifically, the reference forecast has been accepted by the Siting Board as an appropriate base case forecast for use in the analysis of regional need.[38] Altresco Lynn Decision, EFSB 91-102, at 36; EEC (remand) Decision, EFSB 90-100R at 211.

Here, the Company characterized the reference forecast as overly pessimistic, particularly in the near term, and argued that it should be rejected from the analysis of regional need. As noted above, the Company argued that overly pessimistic economic trends, and high fuel price projections dampened the short-term forecast for the years 1992 and 1993 which, in turn, affected the growth in demand projected by the long-term model for the years 1996 and beyond.

In merging the short-term and long-term forecasts, NEPOOL stated in the 1992 CELT Report that it "adjusted the forecast to approach the long-run results smoothly over a two year interim period" (Exh. HO-RR-17(a) at 2-1). The Company raised significant concerns relating to NEPOOL's adjustment of the forecast in the interim period, citing the low CAGR of 0.56 percent over the 1991-1995 period as compared to the CAGR of 2.29 percent over the 1995-2000 period. The CAGR over the 1991-1995 period reflects the lack of growth between 1991 and 1992 (-1.06 percent) and minimal growth between 1992 and 1993 (0.51 percent).

38 As noted by the Company, in previous reviews, the Siting Council also stated its concerns with the 1991 CELT forecast that compromised the validity of the forecast, and, therefore, found that need cases developed from the 1991 CELT forecast should not be used for the purposes of evaluating regional need. See Enron Decision, 23 DOMSC at 42-43; EEC Decision, 22 DOMSC at 235-236.

However, given that the first year of reliance on the long-term forecast is 1996, the reason for the Company's emphasis on relative trends over the 1991-1995 period and 1995-2000 period is unclear.[39] An examination of the average annual increase in growth over the 1991-1996 period, including the transition period, from 1993 to 1996, shows increases in demand significantly larger than the four-year average of 0.56 percent cited by the Company. Specifically, the average annual growth in demand is 0.95 percent for the overall 1991-1996 period and 1.78 percent for the transition period between 1993 and 1996.[40] Further, the growth in demand over the 1996-2000 period is 2.24 percent, less than that over the 1995-2000 period. Thus, although the Company questioned the short-term forecast of growth rate between 1991 and 1993, the rate of growth assumed between 1993 and 1996 is significantly higher. Thus, it is not clear that the low peak load projections for 1992 and 1993 had a significant impact on the long-term forecast. In addition, regarding the Company's arguments that economic indicators show a recovery is already underway, the Siting Board notes that peak load would not necessarily respond immediately to changes in economic indicators.

In sum, the record does not demonstrate that, for the forecast years beyond 1995, the reference forecast is obviously biased, either upward or downward, such as to lead the Siting Board to question the validity of the forecast for those years. Further, the reference forecast has a wide level of recognition for capacity planning purposes in the New England region and has been incorporated directly into CPC's analysis without the need for adaptation by the proponent. Thus, the Siting Board finds that the reference forecast is an appropriate base

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39 The Company's comparison appears to assume that the 2.52 percent increase between 1995 and 1996 is a direct output of the long-term forecast, rather than simply a reflection of the difference between 1995 peak load, which is not part of the output of the long-term forecast, and 1996 peak load, which is within the time frame of reliance on the long-term forecast. There is no evidence to support an interpretation that the long-term forecast method produces results in the form of percentage changes in peak load.

40 The annual transition period increases are 1.44 percent between 1993 and 1994, 1.39 percent between 1994 and 1995, and 2.52 percent between 1995 and 1996.

case forecast for use in the analysis of regional demand for the years 1996 through 2007.

In regard to the high demand forecast, as noted above, CPC considers the high demand forecast to represent a reasonable high demand case. However, given that NEPOOL characterizes the forecast as having only a ten percent chance of occurring, the Siting Board considers the high demand forecast to represent a sensitivity analysis of varying economic assumptions rather than a forecast of regional demand. Thus, the Siting Board does not include the high demand forecast in its analysis of regional need.

(B) High-Low Average Forecast

With respect to the high-low average forecast, the Company notes that the average of NEPOOL's high and low forecast is higher than the 50 percent confidence level, or median level, reflected in the reference forecast. The Company also claims that the high-low forecast produced a 1997 capacity position result that is comparable to that shown in the Resource Assessment's expected values.

The Siting Board notes that, in producing forecast results that are greater than the 50 percent confidence level reflected in the reference forecast as a result of high side uncertainty, the high-low average forecast is conceptually akin to the Resource Assessment's expected values. In the EEC (remand) Decision, the Siting Board stated that, in order to accept an expected value forecast as a base case forecast, a proponent would be required to provide a cost/benefit analysis to support planning to a higher reliability level. EFSB 90-100R at 212-213. Absent such an analysis, the Siting Board found in that review that an expected value forecast was acceptable for consideration in an analysis of regional need, but not as a base case forecast. Id.

Here, in proposing the high-low average forecast as a base case forecast, the proponent has not addressed the cost of planning to a reliability level greater than fifty percent. Accordingly, based on the foregoing, the Siting Board finds that the high-low average forecast is an acceptable forecast for use in an analysis of regional need, but should not constitute a base case forecast.

(C) End-Year Linear Forecast

With respect to the end-year linear forecast, CPC argued that the long-term linear trend would dampen the short-term pessimism of the reference forecast. However the Company did not explain its reasons for choosing a linear format, in particular, to develop a long-term trend, or its reasons for using the end year alone as the basis for determining the slope of the linear trend.

The Siting Board notes that the Company's end-year linear forecast shows higher peak load than the reference forecast for the entire 15-year span of the forecast period, excepting the end year itself. Further, the reference forecast shows its most rapid growth over the latter ten years of the forecast period -- with annual increases in peak load ranging from 434 MW to 672 MW. Thus, the end-year linear forecast is potentially sensitive to the Company's choice of a representative long-term forecast year for purposes of developing the linear trend. While we recognize the intuitive logic of using the end year to represent the long term, CPC might have provided a more balanced basis to develop the long-term trend of its forecast if it had used a range of later years in the forecast, rather than just the end year. In addition, CPC might have provided a clearer rationale for its selection of a linear long-term trend format as part of the end-year forecast approach.

Accordingly, based on the foregoing, the Siting Board finds that the end-year linear forecast is an acceptable forecast for consideration in the analysis of regional demand. However, we recognize that the end-year linear forecast methodology is not sophisticated and may warrant adjustment to reflect a more balanced long-term trend and, therefore, the end-year linear forecast should not be considered for use as a base-case forecast.

(D) Historical Trend Forecasts

With respect to the CAGR regression forecast and the linear regression forecast, CPC maintained that both time-series regression formats are consistent with Siting Council precedent, provide good statistical results, and, barring major structural changes, would continue to demonstrate a strong relationship between time and growth in summer peak load. In addition, CPC maintained that the rate of DSM implementation reflected in these regression forecasts is likely accurate in the short run but too high in the long run due to a likely decline in the rate of growth in DSM resources over time as cost-effective DSM opportunities decline.

In recent reviews, the Siting Board recognized that time-series regression provides no means to capture possible shifts in peak load trends stemming from changes in underlying economic determinants and thus is an unsophisticated forecast methodology. Altresco Lynn Decision, EFSB 91-102, at 38-39; EEC (remand) Decision, EFSB 90-100R at 250-251. In addition, the time-series regression forecasts would not reflect potential differences in the current recovery from recoveries during the 1974 to 1991 time frame.

Further, with respect to DSM, the Siting Board questions CPC's assertion that its time series regressions, based on a 1974-1991 historical period can adequately capture current rates of DSM implementation. The Siting Board notes that, because formal utility programs did not appear until late in the historical period, a majority of peak load data points used in the Company's regression analysis could not reflect the annual amounts of DSM implementation observed in recent years. Thus, unless annual amounts of DSM implementation are significantly smaller over the forecast period than in recent years, the Company's time series regression forecasts can not fully capture DSM trends. See, Altresco Lynn Decision, EFSB 91-102, at 38-39; EEC (remand) Decision, EFSB 90-100R at 250-252.

Nevertheless, overall, time-series regression analyses are a long-recognized benchmark for establishing peak-load trends, and have been considered in previous reviews of proposed generating facilities. Therefore, based on the foregoing, the Siting Board finds that the linear regression forecast and the CAGR regression forecast provide acceptable forecasts for consideration in an analysis of regional demand. However, we recognize that the forecast methodologies are not sophisticated and possible adjustments may be appropriate to reflect DSM trends over the forecast period and, therefore, these forecasts should not be considered for use as the base case forecast.

With respect to the Company's multiple regression forecast, the Siting Board notes that the Company's forecast includes only one independent variable reflecting an economic, demographic or other determinant of load growth, and uses time as a second independent variable. As such, the multiple regression forecast is akin to a forecast based on the historical relationship of peak load to a single economic indicator -- an approach included in previous Siting Board reviews of regional need. While the Siting Board previously has addressed forecasts based on the relationship of peak load to gross national product ("GNP") or gross domestic product ("GDP"), CPC based its multiple regression forecast on the relationship of peak load to another economic determinant, personal income.

In previous reviews, the Siting Board and Siting Council have accepted forecasts based on GDP or GNP as alternative forecasts for the evaluation of regional need while recognizing that such forecast methodologies were not sophisticated. Altresco Lynn Decision, EFSB 91-102, at 40; EEC (remand) Decision, EFSB 90-100R at 213-214; EEC Decision, 22 DOMSC at 236-237. In two recent reviews, the Siting Board found that possible adjustments, however, may be needed to reflect DSM trends over the forecast period when relying on such GDP or GNP forecasts. Altresco Lynn Decision, EFSB 91-102, at 39-40; EEC (remand) Decision, EFSB 90-100R at 213-214.

Here, the Siting Board also is concerned that the forecast methodology, as applied by the Company, had no means to capture possible shifts in the relationship between personal income and peak load that would stem from changes in the rate of DSM implementation. Nevertheless, the Siting Board finds that the multiple regression forecast provides an acceptable forecast for consideration in an analysis of regional demand. However, we recognize that the forecast methodology is not sophisticated and that possible adjustments may be appropriate to reflect DSM trends over the forecast period and, therefore, this forecast should not be considered for use as a base case forecast.[41]

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41 As noted above, during the course of the proceedings, the Company presented three additional demand forecasts -- two forecasts based on alternative fuel price scenarios and one demand forecast based on the DOE forecast of energy use. See n. 22, above. The Siting Board considers these forecasts to represent sensitivity analyses of varying fuel price/energy use scenarios rather than forecasts of regional demand. Further, the Siting Board had no opportunity to question the Company about the development of these forecasts. Therefore, the Siting Board does not evaluate these demand forecasts as part of the evaluation of regional need.

c. DSM

i. Description

CPC indicated that, in order to incorporate DSM savings from utility-sponsored programs into the CELT based forecast, NEPOOL first projects DSM savings over the forecast period by aggregating the DSM forecasts of the individual member utilities (Exhs. CPC-9, at 22; CPC-15, at 84).[42] However, Mr. La Capra asserted that NEPOOL projections of DSM savings likely overestimate the savings that the region will actually experience as a result of utility-sponsored programs (Exh. CPC-9, at 23-24). In support, he stated that in previous CELT forecasts NEPOOL consistently has overestimated the contribution of DSM resources to peak demand reduction (id. at 24). Specifically, he stated that since 1988, actual DSM savings, on average, have been approximately 18 percent less than the DSM forecast by NEPOOL (id. and exh. RLC(24)).[43]

Mr. La Capra explained that NEPOOL's overforecast primarily is due to the manner in which individual utilities project savings from existing and planned DSM programs (id. at 24-26). He stated that utility projections are based on engineering estimates, and that such estimates generally overpredict actual savings as measured by impact evaluations (id. at 26; Exh. CPC-15, at 85).[44] Mr. La Capra stated that a review of the results of DSM

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42 The Company stated that NEPOOL projects a CAGR in DSM of approximately 19 percent per year between 1991-1995, 8 percent per year between 1995-2000, and 4 percent per year between 2000-2007 (Exh. CPC-9, at 21-22).

43 The Company indicated that an analysis of NEPOOL DSM forecast accuracy indicates that: (1) actual DSM was less than the 1988 forecast of DSM by 3.7 percent for 1988, 8.6 percent for 1989, 6.3 percent for 1990 but was more than the 1988 DSM forecast of DSM by 1.8 percent for 1991; (2) actual DSM was less than the 1989 forecast of DSM by 50.4 percent for 1989, 49.4 percent for 1990, and 35.0 percent for 1991; (3) actual DSM was less than the 1990 forecast of DSM by 12.8 percent for 1990 and 12.0 percent for 1991; and (4) actual DSM was less than the 1991 forecast of DSM by 5.4 percent for 1991 (Exh. CPC-9, at exh. RLC(24)).

44 Mr. La Capra stated that some reasons for overestimates include erroneous assumptions in engineering calculations, unanticipated interactions among DSM measures, technical problems, customer behavior changes and weather variations (Exh. CPC-9, at 25).

evaluation studies has found that on average the actual savings from DSM were only 54 percent of forecasted savings, which were based on engineering estimates (Exh. CPC-9, at 25). In addition, the Company asserted that a further reason for NEPOOL overprediction of DSM relates to recent changes in the regulatory climate which may have a slowing effect on implementation of DSM (Company Brief at 46, citing, Exh. CPC-15, at 85).

CPC stated, therefore, that it would be inappropriate to evaluate regional need for new capacity based on the assumption that 100 percent of the utilities' projected DSM savings would be achieved, and instead, a more realistic DSM scenario should be considered (Exh. CPC-9, at 26-27). Thus, the Company provided an alternative DSM forecast as a base DSM case which assumed that DSM growth above 1991 levels would be 25 percent less than the growth forecast by NEPOOL (id.).[45] Mr. La Capra stated that the 25 percent was intended to be a median value, and that in fact 25 percent may be a modest assumption given the current overforecasting of DSM estimates (Exh. CPC-15, at 84-86; Company Brief at 48). He further stated that the 25 percent discount factor for the base DSM case was based on a number of considerations including (1) overall projections on the speed of implementation of conservation measures have been high, specifically overforecasted by almost 20 percent, and (2) the review of utilities actual savings over forecasted savings shows an average saving of only 54 percent (Exh. CPC-15, at 85). CPC also provided a high DSM case which assumed the NEPOOL base DSM forecast (id.; Exh. CPC-9, at 27 and exh. RLC(27)).

ii. Analysis

The Company considered a discount of the 1992 CELT-forecasted DSM by 25 percent of the increment over 1991 levels to be appropriate for the base DSM case. The Siting Board notes that the average actual DSM underperformance for the years 1988 through 1991

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45 The Company stated that under this scenario, DSM continues to grow at a robust rate with CAGRs of approximately 14.29 percent per year between 1991-1995, 6.15 percent per year between 1995-2000, and 3.03 percent a year between 2000-2007 (Exh. CPC-9, at 27).

is 18.2 percent, significantly lower than the 25 percent assumed by the Company. Further, the actual DSM underperformance relating to the 1989 forecast was significantly greater than DSM underperformance relating to the 1988, 1990 and 1991 forecasts, and the record indicates that if the 1989 forecast is omitted from the analysis, the average underperformance is only seven percent.

In reviewing a similar analysis of NEPOOL overforecasting of DSM in the EEC (remand) Decision, the Siting Board noted that the high level of overforecasting in the 1989 CELT Report is not based on historical trends and may be an aberration, contributing to an unwarranted high underperformance average. EFSB 90-100R at 214. Thus, the Siting Board concluded in that review that it would be reasonable to omit DSM underperformance from 1989 in considering the historical basis for any discounting of NEPOOL-projected DSM levels. Id. at 214-215.

By omitting the actual DSM underperformance for 1989 and substituting instead the DSM underperformance for 1990, the next largest DSM underperformance, the average DSM underperformance for the 1988 to 1991 Celt Forecasts is reduced to 8.4 percent. Accordingly, based on the foregoing, the Siting Board finds that it is appropriate to adjust the 1992 CELT-forecasted DSM by 8.4 percent of the increment over 1991 levels and that such adjusted level represents a reasonable base DSM case for the purposes of this review.[46]

As noted above, the Company included the NEPOOL base DSM forecast as a high DSM case. The Siting Board notes that the 1992 Resource Assessment includes high and low DSM forecasts in addition to the base DSM forecast.[47] However, the 1992 Resource

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46 The Siting Board adjustment to the end-year CAGR forecast which incorporates the base DSM case, as adjusted, requires recalculation of the linear trend based on new values for DSM and resultant peak load in 2007. The new peak value for 2007 is 26,914 MW under the adjusted base DSM forecast. The projected growth is 450.9 MW per year.

47 The Siting Board notes that the high DSM values from the Resource Assessment for the years 1996 through 2000 are: 1996 -- 1,943 MW; 1997 -- 2,108 MW; 1998 ---- -- 2,268 MW; 1999 -- 2,456 MW; 2000 -- 2,654 MW, and the low DSM values are: (continued...)

Assessment was published after the Company prepared its regional need analysis. Therefore, for the purpose of this review, the Siting Board finds that the Company's high DSM case which is the 1992 NEPOOL base DSM forecast, represents a reasonable high DSM case.

d. Supply Forecasts

i. Description

CPC presented three supply forecasts based on the 1992 CELT Report, a base supply case, high supply case and low supply case (Exh. CPC-9, at 27-30 and exh. RLC(28)). The Company explained that it considers the base supply case to be the most likely supply scenario, while the high supply case is a somewhat optimistic, although not unlikely, increase in supplies, and the low supply case is a somewhat pessimistic, although not unlikely, decrease in supplies (Exh. HO-N-19).[48]

In support of the supply cases, CPC stated that the base supply case reflects the resources included in the 1992 CELT Report,[49] with three exceptions as follows: (1) a

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[47](...continued)
1996 -- 1,485 MW; 1997 -- 1,612 MW; 1998 -- 1,725 MW; 1999 -- 1,824 MW; 2000 -- 1,922 MW (Exh. JH-1, at 65).

[48] As part of its initial analysis CPC provided contingency scenarios likely to affect either DSM or supply, as adjustments to the base, high and low supply cases (Exh. CPC-1, at sec. 4.2-5). The Company stated that in selecting the contingencies, it focused on supply/DSM contingencies as CPC felt it had adequately captured demand uncertainty through the base and alternative demand forecasts (Exh. HO-N-21). The Company asserted that, although all of the contingencies except one increase expected need, there are many more potential events which could reduce the level of available supplies as opposed to increasing the level of such supplies (Exh. HO-N-22). However, as noted above, an updated contingency analysis was not included in the Company's updated regional analysis.

[49] The resources included in the 1992 CELT report include: (1) existing utility generation; (2) cumulative retirements; (3) cumulative life extensions; (4) committed non-utility generation; (5) net of planned, purchased and sales; (6) other committed capacity additions; and (7) net reratings and deactivations (Exh. CPC-9, at exh. RLC (23)). The Company indicated that the category of committed non-utility generation (continued...)

minor correction to the Vermont joint ownership purchases of Hydro-Quebec power; (2) a deduction from NEPOOL's estimate of capacity to reflect expected attrition and delays of committed future NUG capacity;[50] and (3) exclusion of the capacity of the Wyman 3 unit after the year 2000 (Exh. CPC-9, at 28-30).[51] The Company stated that the high supply case assumes the base case is increased by (1) the continuation of Hydro-Quebec Phase II beyond the year 2000, and (2) 50 percent of the planned, but not yet committed, utility generation project capacity with pending regulatory approval, and 25 percent of the planned, but not yet committed, utility generation project capacity without regulatory approval (id. at 27; CPC-1, at 4.2-8).[52] The Company stated that the low supply case assumes that the base

[49](...continued)
includes those projects fully licensed, with all third-party contracts and financing obtained, and those projects under construction (id.; Exh. HO-RR-15, at 55). The Siting Board notes that neither this proposed project, the proposed Altresco-Lynn, West Lynn, and Eastern Energy projects, nor the Enron project are included in this category.

[50] The Company explained that, historically, a number of NUG facilities with signed contracts have failed to be completed or to come on-line as expected for a variety of reasons including failure to obtain financing, fuel supply or required permits (Exh. AL-2, at 9-15). The Company stated that the Massachusetts Electric Company ("MECo") prepared an analysis of NUG attrition and delay in a 1991 report entitled, "Alternative Energy Negotiation-Bidding Experiment" ("1991 MECo Report"), which includes a wide array of NUG projects at different stages of development (Exhs. CPC-9, at 23; HO-N-16). The Company stated that in updating the 1991 MECo Report, it concluded that the average committed NUG failure rate is 32 percent, and that on average 50.5 percent of NUGs will experience a delay in their projected in service date (Exh. CPC-9, at 23).

[51] CPC stated that NEPOOL inappropriately included the Wyman 3 unit in its total capability for the years beyond 2000 (Exh. CPC-9, at 29-30). CPC noted that this unit was previously listed as scheduled for retirement in the year 2000 (id.).

[52] The Company indicated that these two types of uncommitted utility capacity are categorized in the 1992 CELT Report as categories (L) -- regulatory approval pending, and (P) -- without regulatory approval, respectively (Exhs. CPC-1, at 4.2-8; HO-RR-15, at 54). The record indicates that the principal projects in the L category include (1) the Taunton Energy Center, a proposed 150 MW project, with an expected
(continued...)

case is decreased by the potential early cancellation of utility purchases from outside of NEPOOL, due to short-term excess capacity available within the pool (Exhs. CPC-9 at 27 and exh. RLC(28); CPC-1, at 4.2-8).[53,54]

CPC stated that it assumed a reserve margin of 22 percent of peak demand, consistent with the reserve margin generally used in the CELT Report, a forecast by the New England Governor's Council and recent NEPOOL experience (Exh. CPC-1, at 4.2-6). The Company indicated that the assumption of a 22 percent reserve margin is conservative as the NEPOOL reserve margin has varied between 17.0 percent and 50.2 percent over the 1970-1990 period (Exh. HO-N-13). However, the Company indicated that the 1990 NEPLAN Report called for a reserve margin of 20 to 22 percent between 1996 and the year 2005 to meet its reliability criterion (id.).[55]

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[52](...continued)
start date of January 1995, and (2) the Edgar Energy Park, a proposed 306 MW project, with an expected start date of January 1996 (Exh. HO-RR-15, at 31). The Siting Board notes that a Siting Board decision is pending for the Taunton Energy Center and that the Edgar Energy Park has been indefinitely delayed by the developer, Boston Edision Company. See, 1993 BECo Decision, EFSB 90-12/90-12A at 10. The P category includes 67 MW beginning in 1996, 5 MW beginning in 1997, 100 MW beginning in 1998, and a total of 722 MW beginning in 2000 and beyond (Exh. HO-RR-15, at 31).

53 The Company stated that it determined which supply contracts were likely to be cancelled based on a review of contracts held by purchasing utilities, discussions with purchasing utilities and first-hand knowledge of many of the power contracts held by major New England utilities (Exh. HO-N-18). Further, the Company stated that all of the identified contracts either will expire, although they are potentially renewable, or have an early cancellation provision (id.).

54 The Company calculated the potential NEPOOL purchase reductions as follows: 1992 -- 756 MW; 1993 -- 441 MW; 1994 -- 335 MW; 1995 -- 100 MW; 1996 -- 0 MW; 1997 to 2007 -- 176 MW per year (Exh. CPC-9, at exh. RLC(28)).

55 The Siting Board notes that within the 1992 Resource Adequacy Assessment Executive Report, NEPOOL targeted adjusted required reserve requirements to meet the reliability criterion for the high, reference and low demand forecasts (Exh. HO-JH-1, at Table 3). These reserve margin requirements ranged from: (1) 21 percent to 22
(continued...)

ii. Analysis

As noted above, the Company presented a base supply forecast bsed on the 1992 CELT Report, a high supply forecast based on possible implementation of supply options listed in the 1992 CELT Report and a low supply forecast, based on possible losses of committed capacity included in the base case. The Company characterized the base supply forecast as the most likely supply scenario, while asserting that the high case is a somewhat optimistic, although not unlikely, increase in supplies, and the low case is a somewhat pessimistic, although not unlikely, decrease in supplies. The Siting Board notes that, for all supply forecasts, CPC included NUG capacity only to the extent that such capacity is committed, and is existing or under construction. As noted in Section II.A.4.c. below, the Company excluded the committed capacity of the Enron facility from its original supply forecasts but later amended the Massachusetts supply forecast to include such capacity because the Enron facility was under construction.[56] Accordingly, we will make a comparable correction, i.e, an addition of 83 MW which represents the committed capacity of the Enron facility, to each of the Company's regional supply forecasts in our analysis of regional need.

With respect to the base supply forecast, as noted above, the Company utilized the 1992 CELT Report capacity forecast with a minor correction to the Hydro-Quebec purchase and deductions to reflect (1) attrition and delay of future NUG capacity, based on an analysis of the success rates and operational delays of NUG projects prepared by a utility, and

[55](...continued)
percent for 1998; (2) 20 percent to 22 percent for 1999; and (3) 20 percent to 21 percent for 2000 (id.).

[56] The Siting Board notes that the Company also adjusted the Massachusetts need forecasts to reflect a decrease in Massachusetts purchases from the Power Authority of New York ("PASNY") based on updated data which indicated that original estimates were too high (Exh. JH-RR-2). However, we make no adjustment for purchases from PASNY in the regional analysis because there is no indication in the record of whether there was a change in overall purchases or a change in the allocation of purchases to Massachusetts.

(2) retirement of the Wyman 3 unit after the year 2000.

The Siting Board agrees with the Company's general position that the base supply case should reflect capacity specified in the 1992 CELT Report. However, we have specific concerns with the methodology utilized by the Company in deducting capacity from the 1992 CELT report to reflect NUG attrition and delays. The utility analysis cited by the Company reflected a wide array of NUG projects at differing stages of development. However, the committed NUG projects included in the 1992 CELT capacity forecast are in an advanced stage of development, and thus would not necessarily have the same attrition or delay rate as those included in the utility analysis. For the purposes of deriving a base supply case, it would be preferable to base any adjustments to the 1992 CELT Report capacity forecast on specific circumstances.[57]

Nevertheless, we recognize that some of the committed NUG capacity included in the 1992 CELT Report could be cancelled or delayed. Accordingly, for the purposes of this review, the Siting Board finds that the base supply case, as adjusted by an additional 83 MW, represents a reasonable base supply forecast. In future reviews, the Siting Board will expect adjustments to the CELT Report capacity forecast to be based on specific circumstances for the base supply case.

With respect to the high supply forecast, the Siting Board also has concerns with CPC's consideration of NUG capacity. In recent reviews the Siting Board questioned the exclusion of uncommitted NUG capacity that is existing or under construction from the applicant's supply forecasts and found that such capacity should be included as part of a high supply case.[58] Altresco Lynn Decision, EFSB 91-102, at 48; EEC (remand) Decision,

57 The Siting Board notes that the Company's adjustment to the 1992 CELT capacity forecast to reflect the retirement of the Wyman 3 unit after the year 2000 would not significantly affect the review of need for the proposed facility (see Section II.A.3.e.ii., below).

58 The consideration of the uncommitted capacity of these NUG projects is akin to the consideration of existing but uncommitted utility-owned capacity, such as the extension of the Hydro-Quebec contract, other contracts due to expire, or life extensions for (continued...)

EFSB 90-100R at 224-226. Thus, inclusion of 66 MW of uncommitted capacity of NUG projects that are existing or under construction would be appropriate for the high supply case.

In addition, the Siting Board notes that the Company assumed differing success rates for two categories of planned, uncommitted utility capacity in its high supply forecast. The Company assumed a 50 percent success rate for uncommitted utility capacity classified as "regulatory approval pending," and a 25 percent success rate for uncommitted utility capacity classified as "without regulatory approval." Given uncertainties in planning supply additions, it is reasonable for the Company to assume that not all planned, uncommitted utility capacity will be built and operational as of expected start dates. In fact, the 1992 CELT report includes on-line dates for two proposed utility projects that clearly are uncertain including (1) January, 1995 for the Taunton Energy Center, and (2) January, 1996 for the Edgar Energy Park. See n.52, above. These two projects represent 95 percent of the total capacity included in this category. Thus, a 50 percent success rate for planned utility additions with regulatory approval pending is reasonable. The Company did not, however, provide a rationale for assuming a still lower success rate for the category of planned utility additions without regulatory approval. However, the Siting Board notes that the largest additions in this second category would occur starting in the year 2000 and, therefore, do not significantly affect the review of need for the proposed facility contained herein. See n.52, above.

Therefore, for the purposes of this review, the Siting Board finds that the high supply case, as adjusted by an additional 83 MW of committed NUG capacity, and further adjusted by an additional 66 MW of the uncommitted capacity of NUG projects that are existing or

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[58](...continued)
existing generating units planned for retirement during the forecast period. Although the infrastructure is in place such that the above capacity reasonably could be available, the availability of capacity is not certain over the forecast period and, thus, is appropriate to exclude from the base case. The uncommitted capacity of NUG projects that are existing or under construction includes 3 MW for MASSPOWER and 63 MW for Enron.

under construction, represents a reasonable estimate of a high level of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the high supply case, with the aforementioned adjustments, represents a reasonable high supply forecast for the purposes of this review.

Finally, with respect to the low supply case, the Siting Board notes that the Company's derivation of a low supply case differs in the regional and Massachusetts supply analyses (see Section II.A.4.c.ii., below). For the Massachusetts need analysis, CPC derived its low supply forecast based on a reduction in supply of 632 MW for each forecast year to reflect the unavailability of the Pilgrim nuclear facility. For the regional need analysis, CPC derived its low supply forecast based on potential early cancellation of utility purchases from outside of NEPOOL -- a reduction in supply of 176 MW per year for the 1997-2007 time period but no reduction in supply for the year 1996.

The Siting Board notes that while the low supply forecast figures for regional need appear to be inconsistent with the Massachusetts low supply forecast, as noted in the analysis of Massachusetts need, the Company did not discount its hypothesized loss of the specific nuclear unit to better reflect the limited probability of such a loss. Therefore, the deduction of 632 MW in the Massachusetts low supply case may have been excessive. However, in representing the lower range of supply likely to be available over the forecast period, the Siting Board has concerns that the regional low supply forecast is equal to the base supply forecast for 1996 year and is less than the base supply forecast by only a minimal amount for the 1997-2007 time period. In future cases the Siting Board will expect applicants to provide further justification for related assumptions.

Nevertheless, for the purposes of this review, the Siting Board finds that the low supply case, as adjusted by an additional 83 MW, represents a minimally acceptable estimate of a low range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the low supply case, as adjusted, represents a minimally acceptable low supply forecast for the purposes of this review.

Finally, with respect to the reserve margin, the Siting Board notes that the reserve margin assumed by the Company, 22 percent over the entire forecast period, is likely too high, given NEPOOL's expectations concerning long-term reserve margins. With respect to NEPOOL expectations, the 1992 Resource Assessment Executive Report projects a downward trend in the reserve margin required to meet its reliability criterion. The midpoint of NEPOOL's target reserve margins to meet its reliability criterion for high, low and reference demand forecasts, after 1997, is: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000. Therefore, based on the foregoing, for the purposes of this review, the Siting Board finds that the Company's reserve margin for the years 1998 through 2000 should be adjusted as follows: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000.

e. Need Forecasts

i. Description[59]

The Company developed 33 need forecasts based on a comparison of its eleven demand forecasts -- the reference forecast, the high demand forecast, the high-low average forecast, and the end-year linear forecast each adjusted by base and high DSM scenarios; and the CAGR regression forecast, the linear regression forecast and the multiple regression forecast -- all adjusted by the three supply forecasts -- base, high and low (Exh. CPC-9). In comparing the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 235 MW of capacity in the early years of proposed project operation is: (1) 16 need forecast scenarios, 48.5 percent, in 1996; (2) 26 need forecast scenarios, 78.8 percent, in 1997; (3) 28 need forecast scenarios, 84.8 percent, in 1998; (4) 32 need forecast scenarios, 96.9 percent in 1999; and (5) 33 need forecast scenarios, 100 percent, in 2000 and beyond (id.). See Table 1. The Company indicated that comparison of the high-low average forecast incorporating CPC's base DSM assumptions with the base supply forecast with updated information ("base need scenario") showed a need for over 235 MW in the early years of the proposed project, specifically:

59 In comparing the need forecast scenarios in this section, the base, high and low supply forecasts were increased by 83 MW -- the committed portion of the Enron facility. See Section II.A.3.d.ii., above.

(1) 371 MW in 1996; (2) 1,273 MW in 1997; (3) 2,061 MW in 1998; (4) 2,800 MW in 1999; and (5) 3,379 MW in 2000 (id.). See Table 1.

The Company provided a summary of the 12 common-case need cases, those need cases common to both the regional and Massachusetts need analyses, which indicated that the cumulative number and percentage of cases that demonstrated a regional need for at least 235 MW was: (1) six cases, 50 percent, in 1996 and 1997; (2) seven cases, 58.3 percent in 1998; (3) 11 cases, 91.67 percent in 1999; and (4) 12 cases, 100 percent, in 2000 (Exh. HO-JH-RR-7).

ii. Analysis

As noted above, the Siting Board does not consider the high demand forecast in its analysis of regional need given that NEPOOL characterizes the forecast as having only a ten percent chance of occurring. See Section II.A.3.b.ii.(A)., below. Therefore, the Siting Board focuses on the 27 need forecasts that reflect combinations of six demand forecasts, three of which are adjusted by the two DSM forecasts, and three supply forecasts as adjusted.

In regard to the time period of our need review, the Siting Board notes that it is appropriate to consider need within a time frame beyond the first year of planned facility operation and has previously considered capacity position beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See, Altresco Lynn Decision, EFSB 91-102, at 51-52; EEC (remand) Decision, EFSB 90-100R at 232-233; West Lynn Decision, 22 DOMSC at 14, 33-34. The longer time frame is potentially useful regardless of whether need has been established for the first year of proposed operation. If need has been established for the first year, the longer time frame helps ensure that the need will continue over a number of years, and is not a temporary aberration. If need has not been established for the first year of proposed operation, a demonstration of need within a limited number of years thereafter may still be an important factor in reaching a decision as to whether a proposed project should go forward.[60] Thus, for the purposes of this review, the Siting Board finds that it is appropriate to explicitly consider need for the proposed facility within the 1996 to 2000 time period.

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) all supply forecasts by 83 MW to include the committed capacity of the Enron facility; (2) the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels in the base DSM case; (3) the Company's high supply forecast by 66 MW to include the uncommitted capacity of NUG projects that are existing or under construction; and (4) the Company's assumed reserve margin of 22 percent to reflect lower levels after 1997, specifically 21.5 percent for 1998, 21 percent for 1999, and 20.5 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has found that: (1) the reference forecast is an appropriate base case forecast for use in an analysis of regional demand for the years 1996 through 2007; (2) the high-low average forecast is an acceptable forecast for consideration in an analysis of regional demand but should not constitute a base case forecast; and (3) the end-year linear, linear regression, CAGR regression, and multiple regression forecasts are acceptable for consideration, and provide alternative forecasts, with the caveats as noted above.

While accepting the high-low average, end-year linear, linear regression, CAGR regression, and multiple regression forecasts for consideration in an analysis of regional demand, the Siting Board identified concerns with these approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting Board addresses need based on two compilations of the Company's need forecasts as adjusted (1) a compilation including only those need forecasts incorporating the reference forecast, and (2) an overall compilation including all 27 need forecasts reflecting all six

60 As explained above, an analysis of capacity position is not the only basis by which a facility proponent can establish need. Instead, need also can be established by a combination of factors related to the energy supply. See Section II.A.1.b., above.

demand forecast methodologies.

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 235 MW in each year, from 1996 through 2000, is as follows:

Forecast	1996	1997	1998	1999	2000
Reference forecast (6 cases)	0 (0%)	0 (0%)	0 (0%)	3 (50%)	6 (100%)
Alternative forecasts (21 cases)	6 (29%)	18 (86%)	21 (100%)	21 (100%)	21 (100%)
Total (27 cases)	6 (22%)	18 (67%)	21 (78%)	24 (89%)	27 (100%)

The capacity positions under the need forecasts, as adjusted, are shown in Table 2. Considered with the base DSM forecast, and the base supply forecast: (1) the reference forecast shows a need for 334 MW in 1999; (2) the high-low average forecast shows a need for 1,005 MW in 1997; (3) the end-year linear forecast shows a need for 625 MW in 1997; (4) the linear regression forecast shows a need for 682 MW in 1996; (5) the CAGR regression forecast shows a need for 2005 MW in 1996; and (6) the multiple regression shows a need for 296 MW in 1997.

In sum, six of the Company's 27 need forecasts, including the 21 need forecasts that incorporate the high-low average, end-year linear, linear regression, CAGR regression, and multiple regression forecasts, show a need for at least 235 MW in 1996, 18 show a need for at least 235 MW in 1997, 21 show a need or at least 235 MW in 1998, 24 show a need for 235 MW in 1999, and 27 show a need for 235 MW in 2000. However, none of the six need forecasts that incorporate the reference forecast show a need for at least 235 MW in 1996, 1997, or 1998, only three such forecasts show a need for at least 235 MW in 1999 and all six show a need for at least 235 MW in 2000.

Accordingly, giving added weight to the need forecasts based on the reference forecast for the reasons noted above, the Siting Board finds need for 235 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

f. Economic Efficiency

i. Description

CPC argued that, consistent with the standard of review established by the Siting Council in the Enron Decision, there is a regional need for the proposed project on economic efficiency grounds (Company Brief at 55).[61] The Company indicated that economic efficiency savings available to the region from the proposed project include (1) the variable cost savings which result from displacement by the project of more expensive energy sources in NEPOOL's dispatch order, and (2) the avoided cost of new capacity that would otherwise be required to meet identified regional need (Exh. CPC-9, at 35).

In support, CPC provided a series of detailed economic analyses with and without the proposed facility, based on NEPOOL dispatch practices (id., at 32-37, exhs. RLC(34), RLC(35a), RLC(35b); Exhs. CPC-11, at A24, A25, A26, exhs. RLC(15), RLC(16); HO-N-36c; HO-N-37; HO-N-38; HO-RR-22; HO-RR-23). CPC modelled NEPOOL's load duration curve and dispatch order over the 19-year period 1996-2014 (Exhs. CPC-9, at 33; CPC-11, at A25).[62] CPC stated that it projected a dispatch order for each year of the analysis by adjusting for scheduled plant retirements and additions, adding new generic

61 The Siting Board notes that the standard of review set forth in the Enron Decision predated City of New Bedford. In the EEC (remand) Decision, the Siting Board revisited its standard of review for establishing need in light of City of New Bedford. Specifically, the Siting Board found in that review that it is appropriate to consider economic efficiency benefits to the energy supply as a possible basis for a finding that there is a need for additional energy resources. Thus, the Siting Board reviews the Company's economic efficiency analysis consistent with the current standard of review and past Siting Council precedent.

62 CPC provided an initial economic efficiency analysis for the single year 1995, reflecting only the 1990 CELT demand forecast, but then updated and expanded its analysis to reflect a range of scenarios and incorporate data for the 1996-2014 period as developed in CPC's bid response to Boston Edison Company's RFP 3 (Exhs. CPC-9, at 32-37; CPC-11, at A25, A26; HO-N-36c; HO-RR-22; HO-RR-23).

capacity to meet projected regional capacity requirements,[63] escalating dispatch prices, and reranking generation facilities in order of their new dispatch prices (Exh. CPC-11, at A25).[64,65]

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63 The Company modelled four types of new generic capacity: gas-fired combined-cycle units; oil-fired combustion turbines; coal circulating fluidized bed ("CFB") units; and residual oil steam units (Exhs. CPC-9, at 34; CPC-14, at 55-67). The Company indicated that most assumptions for these units, including fuel prices and variable operation and maintenance ("O&M") costs, were taken from NEPOOL's 1991 GTF report (Exh. HO-N-37). Mr. La Capra noted that the analysis assumed CFB projects would not displace the proposed project in the dispatch queue, both because the proposed project's variable costs are fixed by its bid, and because CFB units may have fairly high variable O&M costs which would be included in the dispatch price (Exh. CPC-14, at 60-62). He added that it was "unlikely" that the next generation of combined-cycle plants would have lower fuel prices than the current generation (id. at 63-66).

64 CPC stated that it modelled NEPOOL's current dispatch order based on plant-specific information for each existing generating facility (Exh. CPC-11, at A25). Specifically, Mr. La Capra stated that obtained plant generating capacity, fuel types, quantity of fuel consumed, average heat rate, unit availability, must-run status, fuel cost, variable non-fuel costs, and dispatch price were obtained for each plant (id.). This information was obtained from FERC Form 1 filings, NEPOOL NX-12 forms, utility plant performance filings with the Department of Public Utilities, and NEPOOL's 1991 GTF report (id.). Initial plant dispatch prices were based on actual NEPOOL dispatch price data for November, 1991 (id.). Dispatch prices for the proposed project were based on the project's bid prices in BECo's RFP 3 (Exhs. CPC-9, at 32; CPC-14, at 29). The Company calculated the "expected annual capacity" for each plant by multiplying its seasonally-weighted average annual capacity by its target equivalent availability factor (Exh. CPC-11, at A25). Mr. La Capra stated that availability factors, as well as ratings and dispatch prices, were adjusted when necessary to account for seasonal variations (Exh. CPC-14, at 41-44).

65 The Company indicated that it assumed that NEPOOL would dispatch on a purely economic basis, with exceptions made for units which must operate for technical or contractual reasons (Exh. CPC-11, at A25). Mr. La Capra stated that a total of 9,196 MW were classified as "must-run" capacity, including all of NEPOOL's nuclear units, conventional hydropower, baseload external purchases, purchases from existing and committed non-utility generation, and portions of certain existing fossil units (id.). He noted that this may overstate future must-run capacity, since: (1) some existing and committed NUGs may be dispatchable, rather than must-run; (2) some units which (continued...)

CPC used two alternative costing methods to estimate the avoided cost of new capacity (1) estimation of avoided capital costs and annually declining carrying charges for utility-owned combustion turbines ("declining carrying charge method"),[66] and (2) estimation of avoided capacity payments based on NEPOOL deficiency charges ("NEPOOL deficiency charge method") (Exh. CPC-9, at 35-36). For each avoided cost method, the Company analyzed a range of scenarios varying assumptions as to: (1) future load growth; (2) future fuel prices; and (3) the mix of future generating units (Company Brief at 60-62, citing, Exhs. HO-RR-22; HO-RR-23).[67] Specifically, CPC analyzed the economic savings attributable to the proposed project for three load growth scenarios, including the reference forecast, the Company's high-low average forecast, and the 1990 CELT Report forecast (id. at 61-62, citing, Exh. HO-RR-23).[68] The Company considered each of these forecasts in conjunction with two fuel price forecasts, the Summer, 1991 DRI forecast, and the May, 1991 forecast by the WEFA Group (formerly Wharton Econometrics) (id.).[69] Finally, in conjunction with

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[65](...continued)
are currently classified as must-run in order to maintain voltage support may not be required if new projects come on-line in the area; and (3) some older must-run units may be retired before the end of the 19-year analysis period (Exh. HO-N-38). Mr. La Capra noted that overstatement of NEPOOL's must-run capacity leads to an understatement of the economic efficiency savings available from the project (id.).

[66] The Company based its estimates of avoided capacity cost under the declining carrying charge method on the 1991 GTF projections of carrying costs (as applied to capital cost, taxes and return) and fixed O&M costs for a utility-owned 80 MW gas turbine unit (Exh. CPC-9, at 35-36).

[67] The Company used its base case supply in these analyses (see Section II.A.3.d., above) (Company Brief at 61, citing, Exh. HO-RR-23).

[68] Mr. La Capra claimed that using the reference forecast as a low demand case and the 1990 CELT Report forecast as a high demand case creates a reasonable range in which future demand might fall (Exh. CPC-14, at 89).

[69] Mr. La Capra indicated that the Summer 1991 DRI forecast predicted flat fuel prices for the first two years, followed by several years of sharp increases and an extended period of slower real growth (Exh. CPC-14, at 81-82). Mr. La Capra stated that he
(continued...)

the 1990 CELT Report forecast and the DRI fuel price forecast only, the Company provided an alternative analysis assuming that the mix of new resources in early years would be 80 percent weighted toward base load capacity, rather than equally weighted between base load capacity and peaking capacity (id. at 61, citing, Exh. HO-RR-22).[70] Thus, the Company presented estimates of the 19-year net economic efficiency effects attributable to the proposed project under seven scenarios and two methods for reflecting avoided capacity cost -- a total of 14 runs.

Based on the Company's overall analysis, the 19-year net present value ("NPV") economic efficiency effects of the proposed project, in 1996 dollars, would range from a slight net loss of $1.3 million to a net savings of $224.0 million (id. at 62, citing, Exh. HO-RR-23). CPC noted that, in general, the estimated savings attributable to the proposed project increase with higher projected demand increases, higher assumed fuel prices, and use of the NEOOOL deficiency charge method to estimate a cost for avoided capacity (id. at 62-63). Referring to the slight net loss at the low end of the range of estimates -- the run based on the reference forecast, WEFA fuel price assumptions, and use of the declining carrying charge method to cost avoided capacity -- the Company argued that (1) the potential loss

[69](...continued)
believed this forecast was probably high, especially in early years, and offered the WEFA Group forecast as a "lowest reasonable boundary" (id. at 90). Mr. La Capra noted that higher fuel prices for the units dispatched after the proposed project result in greater economic efficiency savings attributable to the proposed project (id. at 87).

[70] The Company's original analysis assumed that new generic resources would be split evenly between gas-fired combined-cycle plants (baseload) and oil-fired turbines (peaking) until 1998, after which intermediate oil-fired steam plants and CFB technologies would enter the mix (Exhs. CPC-9; at 34; CPC-14, at 57-58). Mr. La Capra stated that NEPOOL's current mix of 80 percent baseload capacity and 20 percent peaking capacity does not represent the historical mix, and that utilities are likely to correct the imbalance by acquiring additional peaking capacity (Exh. CPC-14, at 69-70). In response to a Siting Board request, Mr. La Capra developed an alternative growth analysis which assumed that this correction would be delayed until 1998, at which time new capacity would be 80 percent baseload, 20 percent peaking (Exhs. HO-RR-22; CPC-14, at 73-77).

under that run is insignificant compared to the potential savings under other runs, and (2) the scenario resulting in such loss (low demand and low fuel prices) is internally inconsistent since the reference forecast is predicated on an expectation of high, rather than low fuel prices (id. at 63).[71]

Mr. La Capra asserted that the economic efficiency savings available from the proposed project would increase under a variety of policies aimed at reducing regional emissions (Exh. CPC-14, at 48-51).[72] Mr. La Capra also claimed that the economic efficiency savings would continue, although at a lower level, in the case of the early retirement of existing generating plants (id. at 51-54). Finally, he indicated that the proposed project's place in the dispatch queue, and hence its economic efficiency savings were related to its low cost fuel supply package (id. at 94-95).

ii. Analysis

In the past, the Siting Council determined that, in some instances, utilities need to add

71 For the four runs based on the 1990 CELT Report forecast and the DRI fuel price assumptions, the Company identified the estimated NPV savings which range from \$99 million to \$224 million in NPV terms (\$69 million to \$491 million in nominal dollar terms) (Company Brief at 60-61). For the run at the low end of the above range, which is the run based on use of the declining carrying charge method to cost avoided capacity and the assumption that the mix of new resources in early years would be 80 percent weighted toward base load capacity, it is notable that the NPV savings of \$99 million are more than the nominal dollar savings of \$69 million, reflecting an apparently irregular distribution of net savings over the 19-year period.

72 Specifically, Mr. La Capra stated that, if high-emission plants added emission control devices, these would be treated by NEPOOL either as a fixed cost, in which case the dispatch order would not be changed, or as a variable operating cost, in which case the proposed project would provide greater savings because of the increased cost of the generation it displaced (Exh. CPC-14, at 48-50). Mr. La Capra also indicated that if NEPOOL changed its practices to dispatch based on variable cost plus an environmental adder, gas-fired plants such as the proposed project would rise in the dispatch order (id. at 50-51). Finally, Mr. La Capra stated that, if an emissions allowance trading program were implemented, gas-fired plants would rise in the dispatch order (id. at 48).

energy resources primarily for economic efficiency purposes. Specifically, in Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985), and in Boston Gas Company, 11 DOMSC 159, 166-168 (1984), 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 with retail service territories outside of Massachusetts, the Siting Board standard indicated that need may be established on either reliability or economic efficiency grounds. Altresco-Lynn Decision, EFSB 91-102, at 15-20; EEC (remand) Decision, EFSB 90-100R at 167-189; NEA Decision, 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. Enron Decision, 23 DOMSC at 49-55; West Lynn Decision, 22 DOMSC at 14; EEC Decision, 22 DOMSC at 210-211; MASSPOWER Decision, 20 DOMSC at 19.

In the MASSPOWER Decision, West Lynn Decision and EEC Decision, the Siting Council rejected Companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Council noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds.

In the Enron Decision, for the first time, the Siting Council found that a non-utility generating project was needed for economic efficiency purposes. 23 DOMSC at 55-62. The Siting Council noted that such a finding, based on comprehensive analyses of NEPOOL dispatch, both with and without a proposed project, is necessarily project-specific. Id. at 58. The Siting Council indicated that, since regional economic efficiency gains are not contractually guaranteed, unlike economic efficiency gains associated with specific PPAs, the degree to which such regional gains are assured would be a critical factor in its evaluation of regional need for economic efficiency purposes. Id. at 58-59. The Siting Council also identified the magnitude and timing of such gains as critical to its review. Id. at 59.

Here, the Company has provided a detailed description of the methodology and assumptions used in its analysis of economic efficiency savings. The Company's methodology is based on reasonable assumptions, and is very similar to that accepted by the Siting Council in the Enron Decision.

Further, CPC's use of multiple scenarios allows the Siting Board to evaluate the degree to which economic efficiency savings are assured in face of uncertainty about future conditions. Specifically, the Company's sensitivity analyses indicate that, over its life, the proposed project will generate significant and quantifiable savings for the region under a range of plausible assumptions regarding potential load growth, fuel prices, avoided capacity costs, and types of generation built in the region in the future.

The Siting Board notes that the lowest of the three load growth forecasts used by the Company in its sensitivity analysis, the reference forecast, was accepted in Section II.A.3.b.ii.(A), above, as an appropriate base case demand forecast in evaluating need for reliability purposes. Of the two remaining forecasts, the 1990 CELT forecast was not included in the analysis of reliability need and the high-low average forecast was included as a possible forecast but not as a base case forecast in that analysis. However, the high-low forecast and the 1990 CELT forecast serve to demonstrate the sensitivity of the Company's economic efficiency analysis results to high-side variability in the demand forecast.

The analyses provided by the Company indicate that, under most of the 14 economic efficiency runs, the proposed project would provide substantial economic efficiency savings over 19 years. However, the timing of annual and cumulative savings is sensitive to the choice of assumptions, particularly those relating to the demand forecast and to the costing approach for avoided capacity.

With respect to the realization of economic efficiency savings prior to the year 2000, the results of the the overall set of 14 runs are mixed. For those runs that incorporate the reference forecast, however, the Company has made no claim and the analyses provide little if any evidence that significant economic efficiency savings would be realized prior to 2000.

In addition, the Siting Board notes that the actual economic efficiency gains that would be achieved under the reference forecast may be less than indicated in the Company's analyses, since the Company's calculations reflect avoided capacity costs beginning in 1996, although the capacity is not needed for reliability purposes until 2000 under that demand forecast. If only the displaced energy cost is considered, it is clear that the proposed project would provide a cumulative NPV 1996-1999 cost displacement well below the cumulative NPV 1966-1999 total fixed and energy cost of the proposed project.[73]

Thus, while the proposed project would provide economic efficiency savings over 19 years under nearly all runs, the Company's analysis failed to show that continuous annual savings would be attained under the reference forecast prior to 2000 -- the first year of regional need for reliability purposes. Therefore, the Company has not demonstrated a need for the proposed project in years prior to 2000, based on economic efficiency.

Further, in discussing its runs that incorporate the 1990 CELT Report forecast and DRI fuel price assumptions, the Company indicated that the 19-year NPV savings under one such run significantly exceed the 19-year nominal dollar savings. The Siting Board notes that such a result apparently reflects a shifting annual pattern of savings and losses, including in particular an occurrence of annual losses during later portions of the period of analysis. Absent an explanation in the record for such a pattern of losses in later years, there is uncertainty as to whether some of the Company's economic efficiency runs that show NPV savings over the 19-year period would continue to show savings if recalculated based on a longer period of analysis.

Nonetheless, we recognize that the Company's estimates of cumulative 19-year savings indicate the potential for significant annual savings over a number of years of proposed project operation. Further, we recognize that any later year losses may simply reflect

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[73] We note that the exclusion of 1996-1999 avoided capacity costs potentially removes or significantly reduces the 1996-2014 NPV savings estimated by the Company under the reference forecast runs. However, we recognize that with a delay in the project on-line date, the Company likely could again show 19-year NPV savings more closely reflecting those it has estimated assuming avoided capacity costs for the overall period of analysis.

particular production cost contract terms, and that there is no evidence in the record that future production costs would preclude long-term economic efficiency savings after current contracts expire or are renegotiated.

Based on the foregoing, the Siting Board finds that CPC has established that New England would realize economic savings of a substantial magnitude from the operation of the proposed project over the likely term of its PPAs, and that, under future demand levels consistent with the reference forecast, economic efficiency savings would begin to accrue on a continuous basis in 2000 or later.

Accordingly, the Siting Board finds that CPC has established that, beginning in 2000 or later, New England will need 235 MW of the additional energy resource from the proposed project for economic efficiency purposes.[74]

4. Massachusetts' Need for Additional Energy Resources

a. Introduction

CPC asserted that there is a need for new capacity in Massachusetts beginning in 1997 or earlier and continuing beyond 1997 (Company Supplemental Brief at 32; Exh. CPC-21 at 15). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based in part on 1992 forecast documents and other data published by NEPOOL and, as necessary, prorated to Massachusetts by the Company (Exhs. CPC-21; HO-MN-26; HO-MN-30; HO-MN-31; HO-MN-32; HO-MN-33). The Company combined its demand and supply forecasts to provide a series of Massachusetts need forecasts, and also subjected the need forecasts to a variety of contingency tests to evaluate the sensitivity of the need forecasts to the uncertainty inherent in the underlying demand and supply forecast assumptions (Exhs. CPC-21; HO-MN-35; HO-MN-36; HO-MN-37; HO-MN-38). In

74 The Siting Board notes that this finding, in and of itself, would not be sufficient to establish need for a project, such as the CPC project, with an expected on-line date of 1996. However, to the extent economic efficiency need is established for the years 2000 and beyond, such finding complements our finding of regional need for the proposed project for reliability purposes in those years (see Section II.A.3.f., above).

addition, the Company presented analyses of transmission system reliability benefits and environmental benefits associated with displacement of more polluting generation by operation of the proposed project (Exhs. CPC-10, at 8-14; HO-MN-6; CPC-9, at 37-41; HO-RR-24; Tr. 4, at 34-37, 42-46).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts which are based on a comparison of the various demand and supply forecasts. Finally, the Siting Board reviews the other factors, i.e. transmission system benefits and air quality benefits, analyzed by the Company in support of Massachusetts need for the project.

b. Demand Forecasts

i. Description

The Company presented 11 forecasts of Massachusetts adjusted peak load demand (Exh. CPC-21, attach. RLC-10). The Company stated that it based its Massachusetts demand forecasts on five different demand forecast methodologies and three different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 5). To derive its 11 demand forecasts, the Company indicated that it adjusted results from three of its forecast methodologies to reflect the three respective DSM forecasts, generating nine demand forecasts and utilized the results from the remaining two forecast methodologies directly without separate reductions to reflect DSM (id.).

(A) Demand Forecast Methodologies

The five demand forecast methodologies utilized by the Company included: (1) the NEPOOL 1992-2007 energy and peak load forecast for Massachusetts ("Massachusetts reference forecast"), a companion forecast to the reference forecast incorporated in the Company's regional need analysis; (2) a Massachusetts expected value forecast, derived from the NEPOOL 1993-1997 expected value load forecast presented in the 1992 Resource Assessment ("Massachusetts expected value forecast"); (3) a variation of the Massachusetts reference forecast, based on a CAGR projection between 1992, or first-year, peak load and 2007, or end-year, peak load as forecasted by NEPOOL in the Massachusetts reference forecast ("Massachusetts end-year CAGR forecast"); (4) a historical time-series linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("Massachusetts linear regression forecast"); and (5) a historical time series CAGR regression forecast, based on a projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("Massachusetts CAGR regression forecast") (id.). The Company stated that its Massachusetts reference forecast was obtained directly from a published NEPOOL source, and the remaining demand forecasts were based on data derived largely from reports published by NEPOOL and NEPLAN (Exh. CPC-21, at 5 and attach. RLC-5; Company Supplemental Brief at 16).

The Company stated that three of its Massachusetts demand forecast methodologies -- the Massachusetts reference forecast, the Massachusetts linear regression forecast, and the Massachusetts CAGR regression forecast -- correspond to demand forecast methodologies used in the regional need analysis (Exh. JH-RR-7).[75] The Company characterized the Massachusetts reference forecast as a reasonable long-term forecast, but cautioned that the

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[75] The Company stated that the base case that it used in the regional analysis -- the median of the high and low forecasts in the 1992 CELT Report -- was not used in the Massachusetts need analysis, as NEPOOL did not develop a high and low demand forecast for Massachusetts (see Section II.A.3.1.(A), above) (Exh. HO-MN-23). Further, CPC indicated that the 1992 Resource Assessment was not available at the time the regional need analysis was conducted, thereby precluding the use of an expected value forecast in that analysis (id.). However, Mr. La Capra asserted that had NEPOOL developed a high and low demand forecast for Massachusetts, he would have submitted the average of the two (as in the regional analysis) as another Massachusetts need case, as well as presenting the expected value derived from the 1992 Resource Assessment for regional need if it were available (Tr. JH-1, at 16).

forecast was overly pessimistic in the short term (Exhs. HO-MN-23; HO-MN-24).[76]

The Company stated that it presented one of its remaining demand forecasts -- the Massachusetts expected value forecast -- as an attractive base case forecast (Exh. HO-MN-23). The Company noted that the expected value forecast is comparable to its base case forecast in the regional analysis -- the median of the high and low forecasts in the 1992 CELT Report (Tr. JH-1, at 17).

To derive the Massachusetts expected value forecast, the Company stated that it prorated, on a year-to-year basis, the forecasted demand in the NEPOOL expected value forecast by the ratio of the forecasted demand in the Massachusetts reference forecast to the forecasted demand in the NEPOOL regional reference forecast (Exhs. CPC-21, at 6; JH-RR-1). The Company stated that, since the reference forecast and the Massachusetts reference forecast are consistent in terms of methodology and assumptions, it is reasonable to use them for purposes of prorating the expected value forecast (Exh. HO-MN-23).

The expected value is the weighted average of all possible outcomes of a probability distribution (Exh. HO-JH-2, at 22; Tr. JH-1, at 47). The Company explained that the expected value is the mean value of the probability distribution (Tr. JH-1, at 47-48). The Company further explained that the 1992 Resource Assessment provided the expected value of the load forecast for the years 1993 through 1997 (Exhs. HO-JH-RR-1; HO-JH-2). CPC then extrapolated values for the years 1998 and beyond based on a linear regression of the NEPOOL forecast data for the 1993 through 1997 period (Exh. JH-RR-1).

In support of its selection of the Massachusetts expected value forecast as a base case forecast,[77] CPC identified the following attributes of the underlying NEPOOL expected

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76 The Company indicated that its Massachusetts reference forecast reflects an average annual growth rate in adjusted peak load of 2.21 to 2.55 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. CPC-21, attach. RLC-10).

77 The Company stated that, over the last three years of the 1992 to 2007 forecast period, the Massachusetts expected value/low DSM combination is the highest forecast, and thus also provides a reasonable high case forecast methodology for that (continued...)

value forecast: (1) it is the product of a sophisticated methodology; (2) it incorporates a probabilistic approach which is preferable to a deterministic approach because it is inherently better able to reflect the potential impacts of the significant uncertainties that affect the timing and magnitude of the need for new energy resources; (3) NEPOOL appears to assign a higher degree of credibility to the resource assessment than the CELT forecast; and (4) it is a conservative basis for planning for new supplies (Exh. HO-MN-23).[78]

In addition to presenting the Massachusetts reference forecast based directly on NEPOOL's deterministic forecast for Massachusetts, the Company presented the Massachusetts end-year CAGR forecast as a useful alternative to the Massachusetts reference forecast (Exh. CPC-21, at 6). The Company indicated that its end-year CAGR forecast methodology assumes that Massachusetts adjusted peak load in 2007 will be the same as forecasted by the Massachusetts reference forecast, but utilizes the average annual 1992-2007 compound growth rate underlying that 2007 peak load level to forecast demand for the intervening years (id.).[79] The Company stated that, by assuming a constant growth rate

[77](...continued)
time frame (Exh. HO-MN-28). The Company indicated that the Massachusetts expected value forecast, although only the third highest forecast during the early years of the forecast period, incorporates higher peak load growth that allows it to surpass all forecasts by the end of the forecast period (Exh. CPC-21, attach. RLC-10). Specifically, the Massachusetts expected value forecast surpasses the Massachusetts linear regression forecast beginning in 1997 to 1999, depending on which of the Company's three DSM forecasts is assumed (id.). Therefore, Mr. La Capra concluded that the expected value forecast with low DSM is overall the best selection for a high case estimate (Tr. JH-1, at 68).

[78] The Company indicated that its Massachusetts expected value forecast reflects an average annual growth rate in adjusted peak load of 2.50 to 2.83 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. CPC-21, attach. RLC-10).

[79] The Company indicated that, to apply the end-year CAGR methodology to adjusted peak load, it first derived Massachusetts adjusted peak load values for 1992 and 2007 by adjusting NEPOOL's Massachusetts peak load forecast to reflect CPC's DSM assumptions for those years, and then derived a CAGR trend forecast of Massachusetts (continued...)

consistent with the long term outcome of the Massachusetts reference forecast, the end-year CAGR methodology dampens the short-term pessimism of the Massachusetts reference forecast, and is likely to be more accurate than the reference forecast over the short and medium terms (Exh. HO-MN-24).[80] The Company added that the use of a constant annual growth forecast for supply planning purposes would decrease the possibility that prolonged periods of oversupply or undersupply of generating capacity would occur (id.).

The Company stated that it developed its Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast by performing time-series regression analyses of 1974-1991 weather-normalized Massachusetts summer peak load data derived from NEPOOL data (Exh. CPC-21, at 7 and attachs. RLC-6, RLC-7).[81] The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the regression equations, and claimed that a moderate to high amount of DSM thus was incorporated in the regression forecasts (Exh. HO-MN-25). The Company indicated that the

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[79](...continued)
adjusted peak load for the intervening years (Exh. CPC-21, attach. RLC-10). The Company indicated that its Massachusetts end-year CAGR forecast reflects a constant annual growth rate of 2.21 to 2.55 percent, depending on which of CPC's three DSM forecasts is used (id.).

[80] As an example of the relatively flat, short-term trend, the Company indicated that its Massachusetts reference forecast projects 1992-1995 increases in adjusted peak load of 1.42 to 1.99 percent, depending on which of CPC's three DSM forecasts is used (Exh. CPC-21, attach. RLC-10). In terms of annual MW increments, the Company's Massachusetts reference forecast shows average annual increases in adjusted peak load of 128 MW to 181 MW between 1992 and 1995, depending on which DSM forecast is used, and 148 MW to 200 MW between 1992 and 1997 -- the on-line date of the proposed project (id.). However, indicative of the higher rate of increase in the longer term, the Company's Massachusetts reference forecast shows average annual incremental increases in adjusted peak load of from 271 MW to 308 MW between 1997 and 2007 (id.).

[81] The Company stated that weather-normalized data was not available by state, and that it approximated such data by multiplying NEPOOL's 1974-1991 weather-normalized summer peak load data by the year-to-year ratio of actual Massachusetts summer peak load to actual NEPOOL summer peak load (Exh. HO-MN-26).

projected growth in Massachusetts peak load would be 179 MW per year under the linear regression forecast[82] and 2.39 percent per year under the CAGR regression forecast (id. at attachs. RLC-6, RLC-10). The Company stated that both regression formats show good statistical results for the 1974-1991 historical data (id. at 7).

The Company asserted that the Massachusetts linear regression forecast represents a reasonable low case, claiming that the Siting Council's decision in the West Lynn Decision supports the view that a linear regression forecast constitutes an "approximate minimum" for a long-term forecast (Exh. HO-MN-29; Company Supplemental Brief at 23).[83] The Company also asserted that the Massachusetts CAGR regression forecast, the highest forecast over all but the last three years of the forecast period, represents a reasonable high case over the 1992-2004 period (Exh. HO-MN-28).

(B) DSM Forecasts

The Company stated that it utilized NEPOOL's DSM forecast for Massachusetts, which corresponds to NEPOOL's DSM forecast for New England contained in the 1992 CELT Report, to develop a range of DSM forecasts for the Massachusetts need analysis (Exh. CPC-21, at 7-8). Repeating arguments from its regional need analysis (see Section

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82 Over the 1992-2007 forecast period, the linear trend corresponds to a CAGR of 1.71 percent (Exh. CPC-21, attach. RLC-10).

83 Based on the Company's projections of adjusted peak load, the Massachusetts linear regression forecast actually is second highest at the beginning of the forecast period, surpassed only by the Massachusetts CAGR regression forecast (Exh. CPC-21, attach. RLC-9). However, depending on which of the Company's three DSM forecasts is assumed, the Massachusetts linear regression forecast is surpassed by the Massachusetts expected value forecast beginning between 1997 and 1999, by the Massachusetts end-year CAGR forecast beginning between 1999 and 2003, and by the Massachusetts reference forecast beginning between 2002 and 2005 (id.). In defending its selection of the linear regression forecast as a reasonable low case, the Company stated that forecasts based on the Massachusetts reference forecast rely on overly pessimistic economic assumptions in the short term (Exh. HO-MN-29). However, the Company stated that the reference forecast with base DSM is a reasonable low demand forecast subject to the prior caveats (id.).

II.A.3.C., above), the Company stated that NEPOOL historically has overforecast DSM, and that, therefore, the Company considers NEPOOL's Massachusetts DSM forecast to be a high case DSM forecast for purposes of the Massachusetts need analysis (id.). Consistent with the regional need analysis, the Company stated that a DSM forecast for Massachusetts which assumes 75 percent of the planned increase in DSM above 1991 levels, as forecast by NEPOOL, would represent a reasonable base case DSM forecast (id.). Mr. La Capra stated that the selection of a 25 percent decrease in DSM is intended to be a reasonable average, since DSM has fallen both at a higher and lower level, but more often at a higher level (Tr. JH-2, at 14). Similarly, the Company stated that it developed a Massachusetts DSM forecast which assumes 50 percent of NEPOOL's planned increase in DSM for Massachusetts above 1991 levels as a low case DSM forecast (Exh. CPC-21, at 8).

ii. Analysis

As described above, the Company utilized five demand forecast methodologies for its Massachusetts need analysis, of which three -- the Massachusetts reference forecast, the Massachusetts linear regression forecast, and the Massachusetts CAGR regression forecast -- correspond to methodologies used in the regional need analysis. The Company generally adopted positions regarding the Massachusetts reference forecast, the Massachusetts linear regression forecast, and the Massachusetts CAGR regression forecast matching those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3.b.i., above.

Consistent with its findings regarding the Company's regional need analysis concerning the 1992 reference forecast, the Siting Board finds that the Massachusetts reference forecast is an appropriate base case forecast for use in an analysis of Massachusetts demand for the years 1997 to 2007.

Further, consistent with its findings regarding the Company's regional need analysis, the Siting Board finds that the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast provide acceptable forecasts for consideration in an analysis of Massachusetts demand. However, we recognize that the forecast methodologies are not sophisticated and that possible adjustments may be appropriate to reflect DSM trends over the forecast period and, therefore, these forecasts should not be considered for use as the base case forecast.[84]

The other two Massachusetts demand forecast methodologies -- the Massachusetts expected value forecast which is the Company's base case, and the Massachusetts end-year CAGR forecast -- do not represent counterparts to forecast methodologies included in the Company's regional need analysis. Therefore, the Siting Board evaluates these forecasts below.

In two recent proposals to construct generating facilities, the Siting Board reviewed an expected value forecast methodology. Altresco Lynn Decision, EFSB 91-102, at 73; EEC (remand) Decision, EFSB 90-100R at 210-212. In its reviews, the Siting Board noted that the applicants' use of the expected value methodology was akin to the use of a a forecast methodology based on planning to a confidence level greater than 50 percent. Id.; See also, Boston Edison Company (Phase I), 24 DOMSC 125, 279-286 (1992) ("1992 BECo Decision (Phase I)"). In addressing such methodoglies, the Siting Board has found that planning to a confidence level greater than 50 percent may be appropriate for reliability purposes, but indicated that as a basis for approval of such planning, submission of a cost/benefit analysis to support planning to a higher reliability would be required. Id. In addition, the Siting Board has noted that a proponent should consider the likelihood that all utilities within NEPOOL would agree to acquire resources based on a confidence level greater than 50 percent. Id.

Here, CPC has not addressed either issue in proposing the Massachusetts expected value forecast as a base case forecast. In order to accept the Massachusetts expected value forecast as a base case forecast, further support would be required including a cost/benefit analysis. Altresco Lynn Decision, EFSB 91-102, at 73; EEC (remand) Decision, EFSB 90-

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84 With respect to the Company's position that Siting Board precedent supports a conclusion that the Company's linear regression forecast is an "approximate minimum" forecast, the Siting Board considered and rejected a similar argument in the EEC (remand) Decision, EFSB 90-100R at 239-240, 251.

100R at 212.

Accordingly, the Siting Board finds that the Massachusetts expected value forecast is an acceptable forecast for consideration in an analysis of Massachusetts demand, but should not constitute a base case forecast.

With respect to the Massachusetts end-year CAGR forecast, the Company claimed that the long-term CAGR trend dampens the short-term pessimism of the Massachusetts reference forecast. However, the Siting Board notes that the Company's Massachusetts end-year CAGR forecast shows higher peak load than the Massachusetts reference forecast for the entire 15-year span of the forecast period, excepting the end-year itself. The Siting Board has addressed the similar use of an end-year CAGR forecast in two recent reviews. Altresco Lynn Decision, EFSB 91-102, at 73-74; EEC (remand) Decision, EFSB 90-100R at 248-249. Like the applicants in those reviews, CPC might have provided a more balanced basis to develop the long-term trend of its forecast if it had used a range of later years in the forecast, rather than just the end-year.

As in those reviews, however, the Company's choice of a CAGR format rather than a linear format to interpolate the peak load forecast values for intermediate years of the forecast period was conservative, i.e., it tended to understate peak load relative to results that otherwise would have been obtained. Id. Thus, although the Company may have developed an unrepresentatively high long-term trend by basing its Massachusetts end-year CAGR forecast solely on NEPOOL's Massachusetts load forecast for the end-year 2007, the Company was conservative in its choice of a CAGR trend rather than a linear trend for purposes of its Massachusetts end-year forecast.

Accordingly, based on the foregoing, the Siting Board finds that the Massachusetts end-year CAGR forecast provides an acceptable forecast for consideration in an analysis of Massachusetts demand.

With respect to DSM, the Company developed base, high and low DSM forecasts for Massachusetts, which in the case of the base and high case were consistent with the DSM forecasts in its regional need analysis, specifically by using the 1992 CELT forecast of DSM additions for Massachusetts as its high DSM forecast, and then discounting those additions by

25 percent and 50 percent in order to develop its base DSM forecast and low DSM forecast, respectively. In its review of the Company's regional need analysis, however, the Siting Board adjusted the Company's DSM forecasts, incorporating a smaller discount factor of 8.4 percent to derive the base DSM forecast.

In addition, the Siting Board has concerns with the Company's selection of its low DSM case. Despite the Company's testimony that engineering estimates, the basis of NEPOOL's current DSM projection, generally overpredict actual DSM savings by 30 to 50 percent (see Section II.A.3.c., above), the Company's discount of DSM growth above 1991 levels by 50 percent appears to be somewhat arbitrary. Further, the Company provided no justification for assuming a lower low DSM case than the 1992 CELT low DSM case which was available at the time the Company presented its Massachusetts need analysis.

The Siting Board also has concerns with the Company's selection of the high DSM case. The Company provided no justification for assuming a lower high DSM case than the 1992 CELT high DSM case. The Siting Board notes that NEPOOL's high and low DSM cases are not disaggregated by state. Thus, to adjust the Company's high and low DSM forecasts it is necessary to prorate NEPOOL's high and low DSM cases to Massachusetts based on the ratio of the adjusted base DSM forecasts in the Massachusetts and regional analyses.[85] Accordingly, for purposes of this review, the Siting Board finds that the Company's low DSM forecast should be adjusted to represent the 1992 CELT low DSM case, and the Company's high DSM forecast should be adjusted to represent the 1992 CELT

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85 With respect to the demand forecasts incorporating the end-year CAGR methodology, the Siting Board adjustments to DSM require recalculation of the CAGR trend based on new values for DSM and resultant peak load in 2007 (see n.46, above). The new peak load values for 2007 with the adjusted DSM values are 12,402 MW under the base DSM forecast, 12,187 MW under the high DSM forecast and 12,731 MW under the low DSM forecast. The new CAGRs are 2.246 percent under the base DSM forecast, 2.126 percent under the high DSM forecast and 2.425 percent under the low DSM forecast.

high DSM case.[86]

Accordingly, the Siting Board finds that: (1) an adjustment of the Massachusetts base DSM forecast by 8.4 percent of the increment over 1992 levels is reasonable for purposes of this review; (2) the Company's Massachusetts high DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT high DSM case; and (3) the Company's Massachusetts low DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT low DSM case.

c. Supply Forecasts

i. Description

The Company stated that it developed base, high and low supply forecasts for Massachusetts (Exh. CPC-21, at 9). The Company stated that it developed its base Massachusetts supply forecast based on the 1992 CELT forecast of committed capacity that is owned or contracted by Massachusetts utilities, regardless of location, but excluded committed capacity in planned NUG projects not yet under construction (id. at 9-10).[87,88] During the course of the proceeding the Company updated the base supply forecast for Massachusetts to include 58 MW, which is the prorated share of the committed capacity of

86 The Siting Board notes that the 1992 CELT high and low DSM cases are derived from the 1992 Resource Assessment, which was not published at the time the Company's regional need analysis was conducted.

87 The Company stated that it obtained Massachusetts committed capacity information directly from the 1992 CELT Report, except that it made adjustments based on other sources in order to: (1) reflect updated plant retirements and additions; (2) identify Massachusetts' 598 MW share of the Hydro-Quebec contract; and (3) identify Massachusetts' share of the PASNY allocations, amounting to 63 MW from 1995 to 1997 and 71 MW from 1998 to 2007 (Exhs. CPC-21, at 9-11, attachs. RLC-12, RLC-13, RLC-14; HO-JH-RR-2).

88 The Company stated that, if Massachusetts supply were based on nameplate capacity of power plants located in Massachusetts, the base case would reflect approximately 1,200 MW less capacity, resulting in earlier or larger Massachusetts need (Exh. CPC-21, at 8).

the Enron facility (Exh. JH-RR-2).

With respect to interstate utilities supplying Massachusetts, the Company stated that the committed capacity of each such utility system was prorated to its Massachusetts service area based on the ratio of Massachusetts to systemwide summer peak load in 1991 (id. at 10).[89] Consistent with its regional need analysis, the Company indicated that it assumed a 22 percent reserve margin applicable to overall supply resources of Massachusetts utilities (id. at 14).

To develop the Massachusetts high supply case, the Company stated that it included 50 percent of the total capacity of uncommitted projects included by Massachusetts utilities in the 1992 CELT report,[90] as well as 50 percent of Massachusetts' share of a possible extension of the Hydro-Quebec contract beyond 2000 (id. at 11). The Company noted that it made no adjustment for the possibility that portions of two projects in the high supply case -- BECo's 306 MW Edgar project and the 150 MW Taunton Energy Center project -- could be sold to non-Massachusetts utilities (id. at 12).

To develop the low supply case, the Company assumed the unavailability of the Pilgrim Unit 1 nuclear facility beginning in 1995, and stated such a case was more than an academic possibility based on the Pilgrim facility's history of operating problems (id. at 11; Exh. JH-RR-2).

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89 The Company stated that the 1991 ratios for the three interstate utility systems -- New England Electric System ("NEES"), Eastern Utilities Associates ("EUA") and Northeast Utilities ("NU") -- are almost identical to the average projected ratios for these systems (Exh. HO-MN-31). The Company presented utility forecast information indicating that, between 1991 and 2001, the ratio of Massachusetts to systemwide summer peak load will decrease by 0.023 and 0.004 for NEES and NU, respectively, but will increase by 0.008 for EUA (id.; HO-MN-31(d)).

90 The Siting Board notes that the high supply analysis for the regional case and the Massachusetts case differs in one respect. The Massachusetts analysis assumes 50 percent of all of the uncommitted projects included in the 1992 CELT Report, class "L" and class "P", while the regional analysis assumes only 25 percent of the class "P" projects -- planned additions without regulatory approval (Exh. HO-MN-32). See Section II.A.3.d., above.

In addition to presenting base, high and low Massachusetts supply forecasts, the Company presented a Massachusetts contingency analysis, consisting of nine contingencies (id. at 12-14).[91] Mr. La Capra stated that of the nine contingencies, there is an equal distribution between base, low and high case assumptions (Tr. JH-1, at 145). The Company presented nine Massachusetts contingency supply forecasts, based on adjusting the Massachusetts base supply forecast to reflect each of the nine Massachusetts contingencies (Exh. CPC-21, attachs. RLC-16, RLC-17).

ii. Analysis

As described above, the Company developed base, high and low supply forecasts that are generally consistent with those used in the regional need analysis. Further, the Company also adopted positions regarding the Massachusetts supply forecasts that are generally consistent with those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.A.3.d.1., above.

Consistent with its findings regarding assumed reserve margins in the regional need analysis, the Siting Board finds that the Company's reserve margin for the years 1998 through 2000 should be adjusted as follows: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000.

Further, in its review of the regional need analysis, the Siting Board adjusted the

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91 CPC stated that the nine contingencies, based on the 1992 CELT Report except where noted, were as follows: (1) addition of 58 percent of planned but uncommitted NUG's (class "C"); (2) life extension of 25 percent of units currently scheduled for retirement; (3) increase in the required reserve margin by 2 percentage points; (4) decrease in the reserve margin by 2 percentage points; (5) retirement of 25 percent of units operating beyond NEPOOL guidelines for retirement, as shown in the 1989 CELT Report; (6) attrition of existing utility units as specified in the expected value case in the 1992 Resource Assessment; (7) attrition of existing NUGs as specified in the expected value case in the 1992 Resource Assessment; (8) the retirement of 33 percent of existing coal units operating beyond retirement guidelines and the assumption that 15 percent of utility coal plants are out of commission for retrofit at any one time; and (9) use of the expected value for Hydro-Quebec Phase II rather than the nominal value (Exh. CPC-21, at 13-14).

Company's high supply forecast to include 66 MW of uncommitted capacity of NUG projects in the region that are existing or under construction. For purposes of the Massachusetts need analysis, it is reasonable to prorate the 66 MW adjustment based on the ratio of the Massachusetts reference forecast to the regional reference forecast. Under that approach, Massachusetts' prorated share of the 66 MW adjustment is 30 MW in each of the years 1997 through 2000. Accordingly, the Siting Board finds that the Massachusetts high supply forecast should be adjusted to include 30 MW of the uncommitted capacity of NUG projects that are existing or under construction.

With respect to the low supply forecast, the Siting Board notes that the Company might have discounted its hypothesized loss of the Pilgrim nuclear unit to better reflect the limited probability of such loss. Nonetheless, loss of Pilgrim for an unusually long period was once experienced, and Massachusetts utilities own significant shares of other nuclear units which also potentially could be off-line for long periods. Thus, the record does not support an adjustment of the Massachusetts low supply forecast.

Based on the foregoing, and consistent with its findings in the regional need analysis, the Siting Board finds that: (1) the Massachusetts base supply case represents a reasonable base supply forecast for the purposes of this review; (2) the Massachusetts low supply case represents a reasonable low supply forecast for the purposes of this review; and (3) the Massachusetts high supply case, as adjusted by 30 MW of the uncommitted capacity of NUG projects that are existing or under construction, represents a reasonable high supply forecast for the purposes of this review.

With respect to the Company's analysis of supply contingencies, the Siting Board notes that a presentation of supply forecasts based on a selection of such contingencies provides a means to assess the plausible range of variability in future supply. However, in previous reviews, the Siting Board stated its concern with compilations of contingency case capacity position results, stating that such compilations represent a weight-of-the-scenario approach without any explicit analysis of the relative probabilities of the scenarios. See, Altresco Lynn Decision, EFSB 91-102, at 80-81; EEC (remand) Decision, EFSB 90-100R at

227-228.[92]

Nevertheless, the Siting Board finds that the Company's Massachusetts supply contingency analysis provides an acceptable basis for assessing the potential range of Massachusetts utility capacity positions that might arise over the forecast period.

d. Need Forecasts

i. Description

The Company presented 33 need forecasts based on a comparison of its 11 demand forecasts with its three supply forecasts (Exh. HO-JH-RR-2, attachs.(c),(d),(e)). Comparing all the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 235 MW of capacity would be: (1) 27 need forecasts, 82 percent, in 1996; (2) 31 need forecasts, 94 percent, in 1997; and (3) 33 need forecasts, 100 percent, in 1998 and beyond (id., attachs. (c),(d),(e)). The Company indicated that a comparison of its base demand forecast -- the Massachusetts expected value forecast with CPC's base DSM assumptions -- with its base supply forecast -- the 1992 CELT capacity forecast with updated information -- showed a need for over 235 MW in the early years of the proposed project, specifically: (1) 561 MW in 1996; (2) 903 MW in 1997; (3) 1,248 MW in 1998; (4) 1,605 MW in 1999; and (5) 1,948 MW in 2000 (Exh. JH-RR-2 (c),(d),(e)). See Table 3.

CPC also presented 99 additional need cases based on (1) adjusting the base supply

92 At the request of the Siting Board staff, CPC supplemented its contingency analysis to also provide a weighted analysis of its supply forecast and contingency case outcomes. (However, the staff did not examine this analysis). We note that the weighted analysis may provide a more reliable basis for the Siting Board's consideration of likely supply forecast variability. However, the Siting Board notes that providing estimated probabilities for an earlier selection of supply forecasts and contingency cases does not necessarily constitute a full and balanced representation, in probabilistic terms, of the actual range of possible outcomes. Although the Company's weighted analysis is a partial reflection of probabilistic techniques, it cannot substitute for a systematically designed probabilistic analysis such as that developed by NEPOOL in the 1992 Resource Assessment.

forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing those nine adjusted supply forecasts with the 11 demand forecasts ("contingency need cases") (id., attachs. (f)-(n)). Considering the Company's contingency need cases together with its need forecasts, CPC presented a total of 132 Massachusetts need cases (id., attachs. (c)-(n)). The Company provided a summary of the results of its overall Massachusetts need analysis which indicated that the cumulative number and percentage of need cases that demonstrate a need for at least 235 MW of capacity would be: (1) 109 cases, 83 percent, in 1996; (2) 126 cases, 95 percent, in 1997; (3) 132 cases, 100 percent, in 1998 and beyond (id., attach. (p)).

The Company indicated that 12 of its 33 Massachusetts need forecasts correspond to need forecasts in the Company's regional need analysis, based on a comparison of the reference forecast, linear regression forecast, and CAGR regression forecast, whereby the reference forecast was combined with two DSM forecasts, and all were combined with the three supply forecasts (Exh. HO-JH-RR-7). The Company provided a summary of results which indicated that the cumulative number and percentage of such need scenarios that demonstrate Massachusetts need for at least 235 MW of capacity would be: (1) 8 cases, 67 percent, in 1996; (2) 10 cases, 83 percent, in 1997; and (3) 12 cases, 100 percent, in 1998 and beyond (id.). Comparing said results to the corresponding results for the regional need analysis -- (1) 6 cases, 50 percent, in 1996; (2) 6 cases, 50 percent, in 1997; and (3) 7 cases, 58 percent in 1998 -- the Company concluded that its analysis demonstrates that need will arise earlier in Massachusetts than in New England as a whole (Exh. HO-JH-RR-7).

The Company also presented two sets of additional calculations of Massachusetts need in response to requests of the Siting Board, including (1) alternative need calculations for most of the Company's need cases, based on assuming a 21 percent reserve requirement instead of a 22.5 percent reserve requirement in the years 1998, 1999, 2000 and 2001,[93]

[93] The Company provided recalculations for 110 need cases, including all 33 need forecasts and 77 of the contingency need cases (Exh. HO-JH-RR-8). The remaining 22 contingency need cases involve contingencies that already reflect higher or lower reserve margins, and thus were not included in the requested recalculations (id.).

and (2) with respect to the three need forecasts that reflect high DSM and base supply, alternative need calculations based on assuming the DSM levels in NEPOOL's high DSM forecast as an alternative to the high DSM levels in the Company's analysis (Exhs. HO-JH-RR-5; HO-JH-RR-8). CPC stated that neither the change in assumed reserve margin nor the change in assumed high DSM levels significantly affects the timing of the first year of continuous need in the Massachusetts need analysis (id.). The Company further indicated that, assuming its base supply forecast in conjunction with the alternative high DSM levels, the first year of continuous need for at least 235 MW would remain 1997 under the Massachusetts expected value and Massachusetts end-year CAGR forecasts but would be delayed by one year under the Massachusetts reference forecast (Exh. HO-JH-RR-5).

ii. Analysis

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) the Company's Massachusetts base DSM forecast to reflect discounting of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels; (2) the Company's Massachusetts high DSM forecast to reflect the NEPOOL high DSM case; (3) the Company's Massachusetts low DSM forecast to reflect the NEPOOL low DSM case; (4) the Company's Massachusetts high supply forecast to include the 30 MW of uncommitted capacity of NUG projects that are existing or under construction; and (5) the Company's assumed reserve margin of 22 percent to reflect lower levels after 1997, specifically 21.5 percent for 1998, 21 percent for 1999, and 20.5 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has accepted the Massachusetts reference forecast as a base case in the long term, and has accepted the Massachusetts expected value forecast, the Massachusetts end-year CAGR forecast, the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast as alternative forecasts for consideration. While accepting the alternative forecasts to the Massachusetts reference forecast for consideration, the Siting Board identified concerns with the alternative approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast. Accordingly, the Siting Board addresses need based on two compilations of the Company's need forecasts as adjusted, i.e., first, a compilation including only those need forecasts incorporating the reference forecast, and second, an overall compilation including all need forecasts reflecting all three demand forecast methodologies.

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 235 MW in each year, from 1996 through 2000, is as follows:

Forecast	1996	1997	1998	1999	2000
Massachusetts reference forecast (9 cases)	4 (44%)	5 (56%)	8 (89%)	9 (100%)	9 (100%)
Alternative Massachusetts demand forecasts (24 cases)	19 (79%)	24 (100%)	24 (100%)	24 (100%)	24 (100%)
Total (33 cases)	23 (70%)	29 (88%)	32 (97%)	33 (100%)	33 (100%)

The capacity positions under the Massachusetts need forecasts, as adjusted, are shown in Table 4. Considered with the Massachusetts base DSM forecast, and the Massachusetts base supply forecast: (1) the Massachusetts reference forecast shows a need for 288 MW in 1997, and 553 MW by 1998; (2) the Massachusetts end-year CAGR forecast shows a need for 612 MW by 1997; (3) the Massachusetts expected value forecast shows a need for 785 MW by 1997; (4) the Massachusetts linear regression forecast shows a need for 921 MW by 1997; and (5) the Massachusetts CAGR regression forecast shows a need for 1,451 MW by 1997.

In sum, 29 of the 33 Massachusetts need forecasts, including the 24 need forecasts that incorporate alternative Massachusetts demand forecast methodologies, show a need for at least 235 MW in 1997, 32 show a need for at least 235 MW in 1998, and 33 show a need for 300 MW in 1999 and 2000. However, only five of the nine need forecasts that incorporate the Massachusetts reference forecast show a need for at least 235 MW in 1997, while eight such forecasts show a need for at least 235 MW in 1998, and all show a need for at least 235 MW in 1999 and 2000.

Accordingly, based on the foregoing, the Siting Board finds a need for 235 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1998. The Siting Board further finds that the Company's need analysis, including its need forecasts and contingency forecasts, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 235 MW of additional capacity will occur earlier than New England's need for the same.

e. Other Factors

In addition to its analyses of need for capacity, CPC argued that the proposed project would provide significant transmission benefits to the Massachusetts energy supply as a direct result of its location in the eastern section of the Rhode Island-Eastern Massachusetts-Vermont Energy Control Area ("REMVEC") (Company Brief at 65). CPC also argued that its proposed project would produce significant environmental benefits to the Massachusetts energy supply as a result of reduced air emissions due to displacement of more polluting generation (id. at 68-72). Consistent with our standard of review, the Siting Board considers the Company's analyses in support of these benefits to determine if they are sufficient to establish need for the proposed project.[94]

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[94] The Siting Board notes that the Company presented these analyses in response to our standard of review for need prior to the Court's decision in City of New Bedford. In the EEC (remand) Decision, we revisited our standard of review for need. In that decision, the Siting Board found that need could be established on reliability, economic efficiency, or environmental grounds directly related to the energy supply of the Commonwealth. See Section II.A.1.c., above.

Specifically, the Siting Board noted that benefits which relate directly to the reliability, cost or environmental impact of the energy supply of the Commonwealth include, but are not limited to, economic efficiency benefits to ratepayers, electric transmission benefits, emissions offsets in the region or at the steam host, and gas/oil swaps with local gas distribution companies. The Siting Board also notes that other benefits not related to the energy supply, while not relevant to the review of need for a proposed project, may still be considered in respect to G.L. c.164 §§ 69I and 69J which (continued...)

i. Transmission Benefits

CPC argued that the proposed project would provide both loading and voltage transmission benefits to Massachusetts (Company Brief at 65-66). CPC stated that, because the eastern portion of the REMVEC area is a net importer of power[95], it is prudent to add electrical power generation in Eastern Massachusetts, thereby relieving constrained transmission facilities within REMVEC and at the interfaces[96] with neighboring transmission and distribution areas (Exhs. CPC-1, at 4.3-1, CPC-10, at 14-17). CPC asserted that relieving such constrained transmission improves transmission reliability and voltage regulation, and allows more transmission to be available for both utility supply and non-utility project access purposes (id.).

Specifically, CPC claimed that the proposed project would improve local transmission circuit loading as a result of the project's proximity to a major local load center (Exh. CPC-10, at 14-17; Tr. 4, at 44-46). The Company stated that currently there are four major generators in the load area encompassing the proposed project, known as the Northeastern Massachusetts supply area ("NEMA area"):[97] Mystic Unit 7, New Boston Units 1 & 2, and Salem Harbor Unit 4 (Exh. CPC-10, at 14-15). The Company indicated that BECo performed several load flow analyses as part of an interconnection study to determine the impact of the proposed project upon interconnection to the NEMA area transmission system

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[94](...continued)
requires that proposals to construct energy facilities be consistent with the current health, environmental protection and resource use and development policies as adopted by the Commonwealth.

[95] CPC stated that more than 75 percent of eastern REMVEC's power requirements are generated elsewhere and imported (Exh. CPC-1, at 4.3-2).

[96] Interface(s) refer to those segments of major transmission lines which link energy control areas such as the eastern REMVEC area to other areas of transmission supply and distribution.

[97] The Company indicated that the major transmission supply to Northeastern Massachusetts includes several 345 kV transmission lines emanating from a Tewksbury, Massachusetts substation (Exh. CPC-10, at 14-15).

(id., attachs. Cabot 100A-100E). The Company stated that the results of the analyses demonstrate that the proposed project could, under certain contingencies, provide load relief to several 345 kV transmission lines (id. at 15-17). The Company noted that, under such contingencies without the proposed project, two such transmission lines, Line 337 from Sandy Pond to Tewksbury and Line 358 from Mystic to North Cambridge, would be approaching their line ratings[98] (id. at 16-17). CPC added that such loading relief could result in a deferral of system upgrades (id.).

Regarding voltage benefits, the Company asserted that operation of the proposed facility would reduce an existing tendency for undesirably high operating voltages on the local transmission system due to variations in reactive power[99] requirements (id. at 9-14). The Company indicated that, at different times, the local supply of reactive power exceeds the demand for reactive power causing these high operating voltages and increasing energy losses on the transmission system[100] (id. at 9).

The Company's witness, Mr. Thalman, explained that a high level of unused VAR

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98 CPC identified three other 345 kV transmission lines for which load flow analyses indicate that operation of the proposed project would provide similar, although less critically needed, loading relief during a contingency: Line 394, which extends from Seabrook to Tewksbury; Line 338, from Tewksbury to Woburn; and Line 339, from Tewksbury to Golden Hills (Exh. CPC-10, at 16).

99 The Siting Board notes that alternating current transmission lines carry "apparent power" (measured in units of volt-amperes ("VA")) -- which is a complex unit of power that reflects the existence of both "real power" (measured in units of watts) and "reactive power" (measured in units of volt-amperes-reactive ("VARS")). Real power refers to that component of the apparent power which performs useful work, e.g, the turning of a motor's shaft, illumination from a light bulb, heat from a toaster, etc. Reactive power refers to that component of the apparent power which is necessary for the proper operation of some devices -- such as establishing necessary magnetic fields in a motor or transformer -- enabling it to efficiently utilize the real power component to do the useful work.

100 To allow a margin for the possible impact of a system contingency involving a varying electrical load, CPC indicated that, under ideal circumstances, the voltage on a 345 kV transmission system should operate between five percent either side of the nominal level (Exh. CPC-10, at 8).

supply contributes to high amounts of underground cable charging currents, an electrical condition associated with the operation of numerous underground circuits in the area (id. at 9,13).[101] The Company further noted that, during periods of light demand for reactive power, the levels of unused VARs on the local 345 kV transmission circuits are excessive (id.; Exh. CPC-1, at 4.3-3). The Company added that high voltage levels currently necessitate periodic operating procedures to reduce excess VARs, including: (1) must-run dispatch of BECo's Mystic facilities; (2) use of shunt reactors on some transmission circuits; and (3) de-energization of other transmission circuits (Exh. CPC-10, at 9-10, 12).

The Company claimed that, based on the electrical effect of adding generation supply at the interconnection point, the proposed project would enhance voltage performance during periods of light load (Exh. CPC-1, at 4.3-3). Mr. Thalman testified that, based on generator operating characteristics and interconnection step-up transformation requirements, the operation of the proposed project would have the capability to absorb 150 megaVARs of reactive power (Exh. CPC-10, at 11-12). CPC asserted that the proposed project, therefore, might reduce must-run constraints at Mystic station, and certainly would add reliability to the area during maintenance of Mystic station facilities (Exh. CPC-1, at 4.3-3). The Company also noted the possibility of deferring utility plans to install additional shunt reactor capacity at Lexington and Mystic substations totalling 90 megaVARs (Exh. CPC-10, at 7-8).

In Turners Falls Limited Partnership, 18 DOMSC 141, 159 (1988), the Siting Council found that transmission-system-related benefits must be significant and carefully documented in order to demonstrate benefits to Massachusetts as part of an analysis of need.

Here, CPC has provided detailed load flow analyses for the NEMA area which indicate the possibility of two, local 345 kV transmission lines approaching their long-term emergency power ratings during a contingency without the availability of the proposed project. The Company did not identify, however, the timing or cost of an actual

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[101] Based on BECo load flow analyses, the Company identified approximate cable charging levels ranging from 88 to 120 megaVARs for each of five underground 345 kV circuits in the area (Exh. CPC-10, at 13).

improvement to address an identified need based on (1) expected load growth and applicable reliability standards, or (2) specific confirmation of a utility plan to implement such improvements. Nonetheless, the evidence provided by the Company demonstrates that the proposed project could provide load relief to the local transmission system under certain contingencies and thereby delay the need for transmission improvements in the local area.[102]

With respect to importation of power to REMVEC over transmission interfaces with adjoining transmission and distribution areas, CPC has provided no load flow or other detailed analyses to establish that such interfaces would benefit as a result of operation of the proposed project. The Siting Council and Siting Board have consistently held that such detailed analyses must be provided to establish that Massachusetts would receive benefits based on transmission-related needs of REMVEC as a whole. Altresco Lynn Decision, EFSB 91-102, at 88-89; Enron Decision, 23 DOMSC at 68-69.

With respect to voltage benefits, we note that CPC's claim that the proposed project would help stabilize excessive voltage levels due to reactive power surpluses were not fully substantiated. CPC quantified the potential excess VAR supply based on contingency load flow analyses and identified apparent operating implications for area utilities. However, CPC failed to adequately document the nature, cost and timing of measures utilities would consider and select to address any such excess VAR supply, with or without the proposed project.

Thus, CPC has identified only the potential for the proposed project to provide local reliability benefits by (1) deferring likely need for transmission projects to meet increased

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[102] The Siting Board notes that Section IV of the 1993 CELT Report -- Scheduled and Proposed Transmission Changes of Bulk Power Lines -- lists a 4.7-mile section of new 345 kV line extending from the Mystic Station in Everett to a North Cambridge substation as scheduled for service in 1997. Although this information became available after the close of the record in this proceeding, the Siting Board further notes that this scheduled change is consistent with the load flow analyses provided by CPC which included an existing 345 kV circuit between Mystic Station and North Cambridge among those approaching their respective power ratings (Exh. CPC-10, at 16, attach. Cabot 100A-100E).

local load, and (2) possibly deferring likely need for new shunt reactor facilities or reducing existing need for operating measures to control excess VARS. While such contributions to meeting reliability needs clearly represent potential benefits to Massachusetts, the Siting Board must evaluate the timing of identified needs and the availability and cost of alternatives, in order to determine whether such benefits are of sufficient magnitude to contribute to a showing of need for the proposed project. Here, the Company has not demonstrated that there is a need for the proposed project based on transmission reliability benefits for specific future years, neither prior to 2000 nor later in the life of the project.

Accordingly, the Siting Board finds that the Company has not established a need for the proposed project based on transmission reliability.

ii. Air Quality Benefits

CPC argued that the proposed project would produce substantial environmental benefits to both the Massachusetts and New England energy supply in the form of reduced air pollutant emissions which would result from the displacement of higher emission-generating power sources by the operation of the proposed project (Company Brief at 68-72). In addition, the Company indicated that emissions associated with the vaporization of LNG at the DOMAC facility would be displaced by the operation of the proposed project (Exhs. HO-E-19; HO-E-27; HO-E-75).

To demonstrate environmental benefits realized from the displacement of existing sources of air emissions, the Company presented a dispatch analysis[103] comparing emissions of seven major pollutants associated with the combustion of fossil fuels both with and without the proposed project: (1) sulphur dioxide ("SO_2"); (2) nitrogen oxides ("NOx"); (3) particulates ("PM-10"); (4) carbon monoxide ("CO"); (5) volatile organic compounds ("VOCs"); (6) carbon dioxide ("CO_2"); and (7) methane (Exh. CPC-9, at 37-41 and exh.

[103] The Company indicated that the overall methodology and assumptions employed in the emissions displacement analysis were identical to those employed in the economic efficiency analysis (Exh. CPC-9, at 38). See Section II.A.3.f., above.

RLC(37), exh. RLC(38), exh. RLC(39)).[104] The Company indicated that emission calculations were based on projected unit-specific emissions rates for the year 1996 (id., at 39).[105]

Based on the results of this analysis, CPC claimed that the operation of the proposed project would significantly reduce regional emissions of SO_2, NOx, VOCs, CO, PM-10, CO_2, and methane beginning immediately in 1996 and continuing through the year 2014 (id. at RLC(38)). CPC added that, for Massachusetts specifically, operation of the proposed facility would reduce emissions of SO_2, NOx, VOCs, CO and PM-10, but would increase emissions of CO_2 and methane (id.).[106]

CPC additionally indicated that operation of the proposed project would provide sufficient thermal energy for the vaporization of LNG at the DOMAC facility, and as such, would eliminate combustion of 800 billion British thermal units ("Btu") per year of natural gas for vaporization purposes at the DOMAC facility (Exhs. HO-E-27; CPC-1, at 3.2-1). The Company provided estimates of annual emissions reductions at the DOMAC LNG facility that would result from the use of CPC-produced thermal energy, based on projected 1996 DOMAC vaporization capacity (Exhs. HO-E-27; HO-E-75). Estimated emissions reductions include approximately: (1) 58 tpy of NOx; (2) 14 tpy of CO; (3) 0.18 tpy of PM-

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104 The Company analyzed dispatch effects for each year from 1996 through 2004, for 2009, and for 2014, and provided interpolated values for the remaining years (Exh. CPC-9, at exh. RLC(38)).

105 Mr. La Capra indicated that emissions data incorporated expected changes in the region's generation fuel mix, including conversion of a Boston Edison unit to natural gas and conversion of certain New England Power units to lower sulfur fuels (Exh. CPC-9, at 38-39).

106 The Company also provided alternative emissions analyses which included alternative projections regarding load, fuel prices, and generation mix (Exh. HO-RR-24 and attachments). CPC noted that the results of these analyses indicate that the total emissions savings to New England are not especially sensitive to assumptions regarding projected demand, fuel prices, or future supply mix (id.). CPC further noted that the results of these analyses indicate that the total estimated emissions reduction savings in Massachusetts would be more sensitive to input assumptions (id.).

10; and (4) 48,000 tpy of CO_2 (id.).[107]

The Siting Board has held that a project proponent must provide full documentation of its assumptions pertaining to environmental benefits associated with the dispatch of generation capacity. Altresco Lynn Decision, EFSB 91-102, at 92. See also Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

In the Enron Decision, the Siting Council found for the first time that a proposed generating project would provide Massachusetts with environmental benefits related to net changes in air emissions from existing and future generating facilities in Massachusetts. 23 DOMSC at 69-73. In two more recent decisions, the Siting Board has found that applicants' projects likely would provide short-term air quality benefits for Massachusetts based on the initial displacement of existing generation and associated emissions.[108] Altresco Lynn Decision, EFSB 91-102, at 93-95; EEC (remand) Decision, EFSB 90-100R at 94-104. However, the Siting Board identified shortcomings of those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly redispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million BTu ("MMBTu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. Altresco Lynn Decision, EFSB 91-102, at 93; EEC (remand) Decision, EFSB 90-100R at 101-102.

The Siting Board recognized in those reviews that load growth represents a given for purposes of the Company's dispatch analysis, and that the analysis must assume dispatch of available capacity to meet load growth over time. Altresco Lynn Decision, EFSB 91-102, at

[107] The Company indicated that DOMAC's use of natural gas to vaporize LNG does not produce SO_2 emissions (Exhs. CPC-1, at 3.2-1; HO-E-27).

[108] In the Altresco Lynn Decision, the Siting Board reviewed the most complete dispatch analysis to date -- a 20-year dispatch analysis which assumed that energy requirements would be met by currently claimed committed capacity and, as necessary, a range of generation expansion scenarios. EFSB 91-102, at 90-95.

93; Eastern (remand) Decision, EFSB 90-100R at 102. In the EEC (remand) Decision, the Siting Board further recognized that, to the extent that the applicant's project would in whole or in part replace existing generation that potentially will be permanently retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation.[109] EFSB 90-100R at 102. Here, CPC has provided the Siting Board with a comprehensive 19-year analysis of dispatch effects on state and regional emissions for the period 1996-2014 which is similar to the 20-year analysis reviewed by the Siting Board in the Altresco Lynn Decision. EFSB 91-102, at 92-93. The CPC 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 -- for the Siting Board to be able to evaluate whether there would be significant dispatch related benefits to the regional and Massachusetts energy supply specific to operation of the proposed project.

For the purposes of assessing environmentally based need in Massachusetts, the Siting Board here focuses primarily on CPC's calculations of the net impact that the proposed project would have on the total emissions from generating facilities located in Massachusetts. CPC's analysis indicates that, under a range of realistic generation expansion scenarios, the operation of the proposed project would clearly reduce the net emissions in Massachusetts of five of the seven pollutants analyzed: SO_2, NOx, CO, PM-10, and VOCs. These net reductions, however, are offset to a degree by the higher net Massachusetts emissions of CO_2 and methane.[110] However, the Siting Board notes that emissions of two pollutants which

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109 The Siting Board also noted that similarly favorable long-term air quality results may also be achieved through a combination of (1) implementing new base load generation with low emissions, and (2) implementing new emissions controls at existing generating units capable of reducing emissions rates from such units. Altresco Lynn Decision, EFSB 91-102, at 94.

110 Recognizing that a significant increase in levels of CO_2 are of possible concern regarding climatic changes on a global scale, the Siting Board notes that the net regional reduction in CO_2 is likely of substantially greater importance than the net Massachusetts increase in CO_2 emissions.

are of greatest concern to regional acid rain and ground-level ozone problems, i.e., SO_2 and NOx, would be reduced significantly by the operation of the proposed project.

Thus, the Company's dispatch analysis, considering on balance the criteria and other pollutants identified therein, demonstrates that the proposed project would, at a minimum, provide short-term air quality benefits for Massachusetts based on its displacement of existing generation and associated emissions of several important pollutants.

However, as in previous reviews of such dispatch analyses, it is unclear that the air quality benefits for Massachusetts based on initial displacement of existing generation and associated emissions would be long-term. The Company's analysis is similar to those in previous reviews in that it: (1) allows the displaced generation to be increasingly redispatched over time with continued load growth; (2) assumes that the emissions rates from respective units in the analysis, in lb/MMBtu, remain constant over time; and (3) includes no explicit assumptions or scenarios demonstrating a potential for holding Massachusetts emissions to current or lower levels through planned or accelerated retirement of existing generation.

With respect to the displacement of emissions from the DOMAC facility as a result of thermal energy sales from the proposed project, the Siting Board and Siting Council previously have considered the potential for applicants' cogeneration projects to provide air quality benefits to Massachusetts based on net emissions reductions at the site, i.e., expected reductions in an existing steam host's steam production facility emissions that are greater than expected total emissions from the applicant's cogeneration project. Altresco Lynn Decision, EFSB 91-102, at 94-95; MASSPOWER Decision, 20 DOMSC at 329-330; Altresco-Pittsfield Decision, 17 DOMSC at 368. In each of these previous reviews, applicants demonstrated that their cogeneration projects would result in a net reduction in SO_2 emissions but a net increase in NOx emissions. Id. In the Altresco-Pittsfield Decision, the Siting Council found that the SO_2 reduction outweighed the NOx increase and that the applicant's cogeneration project, therefore, would provide environmental benefits based on displacement of steam production facility emissions. 17 DOMSC at 368.[111]

Here, CPC has provided documentation indicating the emissions reductions that would be realized by the proposed project's thermal energy agreement with DOMAC, and DOMAC's resultant reduction in natural gas requirements to vaporize LNG. However, such emissions reductions would be less than the increase in emissions expected from the proposed project for all criteria pollutants and CO_2. Thus, operation of the proposed facility would result in a net increase in local air emissions.

Accordingly, the Siting Board finds that CPC has demonstrated that the proposed project would provide short-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts. However, the Siting Board finds that CPC has not demonstrated that the proposed project would provide long-term environmental benefits to Massachusetts based on reduction of air pollutant emissions from generating units in Massachusetts. Further, the Siting Board finds that CPC has not demonstrated a significant improvement in air quality in the vicinity of the proposed facility due to the displacement of DOMAC's existing thermal production for LNG vaporization.

Accordingly, the Siting Board finds that CPC has failed to establish that the proposed project is needed on environmental grounds.

5. Conclusions on Need

The Siting Board has found that CPC has not established that its proposed project is needed for economic efficiency or reliability reasons in Massachusetts through signed and approved PPAs. The Siting Board further has found that there will be a need for 235 MW or more of additional energy resources in New England for reliability purposes beginning in 2000. The Siting Board also has found that CPC has established that in the year 2000 or later New England will need 235 MW of additional energy resources from the proposed

111 The Siting Board notes that in the Altresco-Pittsfield Decision, the displacement of the steam host's steam production emissions was guaranteed because the steam host was under a Massachusetts Department of Environmental Protection ("MDEP") order to replace its boilers. 17 DOMSC at 368.

project for economic efficiency purposes. Further, the Siting Board has found that there will be a need for 235 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1998. Finally, the Siting Board has found that the Company has failed to establish need for the proposed project based on transmission system reliability grounds or environmental grounds.

Based on the foregoing, the Siting Board has found that the Company's need analyses demonstrate that Massachusetts' need for 235 MW of additional capacity will occur earlier than New England's need for same. Given the demonstration of earlier need in Massachusetts than New England, it is clear that, for all years in which there will be a regional need for the proposed project, i.e., for the years 2000 and beyond, the proposed project would provide a necessary energy supply for the Commonwealth.[112] The proposed

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112 The Siting Board hereby takes administrative notice of recent electric forecast cases concluded by the DPU and the Siting Council. In Fitchburg Gas and Electric, 24 DOMSC 322, Table 3 and Table 4 (1992), the Siting Council approved a forecast showing that in the summer of 1995, the last year of its forecast, Fitchburg Gas and Electric Company would have a total capacity of 102.10 MW, resulting in a surplus of 19.1 MW over its "capability responsibility" of 83.0 MW and a surplus of 26.2 MW over its summer peak load of 75.9 MW (at Table 3 and Table 4). In Boston Edison Company (Phase I), 24 DOMSC at 303, the Siting Council found that Boston Edison Company would have surplus capacity of 149 MW in 1996 and 120 MW in 1997, the last year included in its forecast. In Eastern Utilities Associates, DPU 92-214, (1993), the Department approved a forecast showing that for 1996, the last year in its forecast, Eastern Utilities Associates would have a base case summer peak load surplus of 197.6 MW. In Commonwealth Electric Company\Cambridge Electric Light Company, DPU 91-234, Table 3 (1993), the Department approved a forecast indicating that the Cambridge Electric Light and Commonwealth Electric Companies would have a supply surplus through the year 2000, specifically a surplus of 116 MW in the winter of that year. The Department and the Siting Council approved settlements in four other proceedings filed pursuant to 220 C.M.R. § 10.00 et seq., the Integrated Resource Management Regulations. However, these settlements do not establish precedent nor does the Department's acceptance of the settlements constitute a determination or finding on the merits of any aspect of these proceedings. See Fitchburg Gas & Electric Co., D.P.U. 92-181, at 22 (1993); Boston Edison Company, D.P.U. 92-265 (1993); Western Massachusetts Electric Company\Northeast Utilities, D.P.U. 92-88, at 9-10 (1992); Massachusetts Electric Company\New England Power

(continued...)

project on-line date, however, is 1996. Thus, the Siting Board must evaluate whether the project is needed beginning in the year 1996.

In the EEC (remand) Decision, EFSB 90-100R at 188, the Siting Board noted that an applicant could establish that a regional capacity surplus might not be available to meet a Massachusetts capacity deficiency as a result of transmission or other reliability constraints. The Siting Board further noted that an applicant could establish that reliance on a regional capacity surplus would be contrary to providing a necessary energy supply at the lowest possible cost with the least environmental impact.

However, this recognition was set out in the EEC (remand) Decision after the record in this proceeding was fully developed. Thus, in this case, a record on this issue has not been developed. The record shows that for the years 2000 and beyond there is a need of 235 MW or more for both Massachusetts and the region. However, the record is unclear regarding the ability of Massachusetts utilities to acquire surplus supplies from out-of-state providers in years in which there is a Massachusetts deficiency of 235 MW or more, and either a regional deficiency of less than 235 MW, or a regional surplus. Therefore, based on the record, the Siting Board is unable to determine that the proposed project is needed to provide a necessary energy supply for the Commonwealth prior to the year 2000.

The Siting Board notes that a similar disparity occurred between the timing of Massachusetts and regional need in two previous reviews of proposed generating facilities. In the EEC (remand) Decision, EFSB 90-100R at 266-267, a review of a proposed 300 MW coal-fired facility, the Siting Board found that there was a need for at least 300 MW of additional energy resources in New England for reliability purposes beginning in 2000 and a need for at least 300 MW of additional energy resources in Massachusetts for reliability purposes beginning in 1998. In that decision, the Siting Board determined that it was appropriate to require the Company to submit PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. The Siting Board

[112](...continued)
Company, EFSC 91-24\D.P.U. 91-114, at 5 (1991).

found that the amount of facility output subject to signed and approved PPAs that would be sufficient to establish Massachusetts need would depend on other factors which contribute to Massachusetts need as well as the size and type of facility. Thus, the Siting Board found that the submission of (1) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which is the result of a competitive resource solicitation process beginning in 1993 or beyond and which is approved pursuant to G.L. c. 164, sec. 94A will be sufficient evidence to establish that the proposed project will provide a necessary energy supply for the Commonwealth. See, EEC (remand) Decision, EFSB 90-100R at 268.

In the Altresco Lynn Decision, EFSB 91-102, at 54, 85, a review of a proposed 170 MW natural gas-fired facility, the Siting Board found that there was a need for at least 170 MW of additional energy resources in New England for reliability purposes beginning in 2000 and a need for at least 170 MW of additional energy resources in Massachusetts for reliability purposes beginning in 1997. In addition, the Siting board found economic efficiency need in 2000 or later. In that decision, the Siting Board also determined that it was appropriate to require the Company to submit PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. Thus, the Siting Board found that submission of signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's output would be sufficient to establish that the proposed project would provide a necessary energy supply for the Commonwealth. Id. at 99.

Here, the proposed facility is a 235 MW, gas-fired facility. As noted above, the amount of facility output subject to signed and approved PPAs sufficient to establish Massachusetts need would be dependent on the size and type of facility as well as other factors which contribute to need. In the EEC (remand) Decision in comparing the proposed project to technology alternatives, the Siting Board found that the proposed project would be superior to all technology alternatives reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. EFSB 90-

100R at 165. However, the Siting Board also found that the natural gas combined-cycle alternative would offer greater environmental benefits to the energy supply relative to the proposed project and that the proposed project would offer greater cost and reliability benefits to the energy supply relative to the natural gas combined-cycle alternative. Id.. In the Altresco Lynn Decision, in comparing the proposed project to technology alternatives, the Siting Board found that the proposed project would be superior to all technology alternatives reviewed with respect to providing a necessary supply with a minimum impact on the environment at the lowest possible cost. EFSB 91-102, at 129. The Siting Board further found that the proposed project would offer greater environmental, cost and reliability benefits to the energy supply relative to the technology alternatives examined. Id. at 99.

Here, in comparing the proposed project to technology alternatives, the proposed project also is superior to all technology alternatives reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. Further, the proposed project also would offer greater environmental, cost and reliability benefits to the energy supply relative to the technology alternatives examined (see Section II.B., below). In addition, this project has established need on both reliability grounds and economic efficiency grounds beginning in 2000.

In light of the need for the proposed project beginning in the year 2000 on reliability and economic efficiency grounds, the Siting Board finds that submission of signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electric output, will be sufficient to establish that the proposed project will provide a necessary energy supply for the Commonwealth. CPC must satisfy this condition within four years from the date of this conditional approval. CPC will not receive final approval of its project until it complies with this condition. The Siting Board finds that, at such time that CPC complies with this condition, CPC will have demonstrated that the proposed project will provide a necessary energy supply for the Commonwealth.

B. Alternative Technologies Comparison

1. Standard of Review

G.L. c. 164, § 69H, requires the Siting Board 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, § 69J, requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing, and other site locations; (b) other sources of electrical power or gas, including facilities which operate on solar or geothermal energy and wind or facilities which operate on the principle of cogeneration or hydrogeneration; and (c) no additional electric power or gas.

In implementing its statutory mandate, the Siting Board requires 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. Altresco Lynn Decision, EFSB 91-102, at 100; EEC (remand) Decision, EFSB 90-100R at 65. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Board determines whether the project offers power at a cost below the purchasing utility's avoided cost. Altresco Lynn Decision, EFSB 91-102, at 100; EEC (remand) Decision, EFSB 90-100R at 65; NEA Decision, 16 DOMSC at 360-380.

2. Identification of Resource Alternatives

The Company asserted that it has demonstrated through analyses that there is both a regional need and a Massachusetts need for at least 235 MW of new capacity on reliability and economic efficiency grounds beginning in 1996 (Exhs. CPC-21; HO-RR-22). To address such an identified need of additional energy resources, CPC proposes to construct a nominal 235 MW gas fired, combined-cycle cogeneration facility in Everett, Massachusetts which would commence commercial operation in 1996 (Exh. CPC-20, at 8).

The Company stated that, as a threshold for considering alternative energy resources, it eliminated any alternative which it perceived as being unable to meet, or grossly exceeding the identified need.[113] The Company added that it examined alternate approaches to addressing the identified need, including several conventional technologies which have the ability to meet the identified need (id., at 4). CPC stated that it evaluated alternatives in terms of size, reliability, technological maturity, construction time frame, siting/permitting feasibility, fuel availability, and compatibility with cogeneration and non-utility generation (id.). The Company indicated that any alternative would have to supply both the region's need for power and DOMAC's need for thermal energy (Tr. 7, at 8).

In regard to DSM, the Company stated that it has already included all presently identified cost-effective DSM in the need analysis (Exh. CPC-21, at 7-8). The Company argued that the governing statute requires the consideration of DSM as a reduction in electric-power requirements, and as such, DSM does not need to be considered in the alternatives comparison (Company Supplemental Brief at 58).[114]

Based on these considerations, the Company stated that it identified five alternatives that would be capable of meeting the identified need, in lieu of the Company's proposed project (Exh. CPC-20, at 5-6). Specifically, CPC identified: (1) a duel-fuel, combined-cycle plant with an interruptible 10-month gas supply and a 2-month distillate oil backup

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[113] CPC stated that it did not consider in detail, small units including: (1) municipal solid waste; (2) biomass; or (3) wind turbine facilities (Exh. CPC-20, at 5). The Company added that the City of Everett does not allow the operation of solid fuel generating facilities within the city limits (Tr. 7, at 9). CPC stated that it did not consider larger units with more generating capacity than is required, such as nuclear fission (Exh. CPC-20, at 5). CPC further stated that it also eliminated from consideration technologies with an immature development status, such as nuclear fusion, photovoltaic cells, compressed air energy storage, fuel cells, and battery storage, or technologies for which local resources would be inadequate to develop (e.g., geothermal and hydropower, etc.) (id.; Tr. 7, at 7). CPC added that certain large-scale coal technologies, such as coal gasification, were also eliminated on the basis of site constraints (Tr. 7, at 17).

[114] The Siting Board notes that its statute requires that projections of demand must include "an adequate consideration of conservation and load management." G.L.c. 164, §69J. In the EEC (remand) Decision, the Siting Board found that an analysis of load management as an alternative to the planned activity is not required by the statute. EFSB 90-100R at 56.

("gas/oil GTCC alternative"); (2) a distillate oil-fired, combined-cycle plant ("oil-fired GTCC alternative"); (3) a CFB plant ("CFB alternative"); (4) a conventional pulverized coal steam unit ("pulverized coal steam alternative")[115]; and (5) a residual oil-fired steam plant ("residual oil steam alternative") (id.).

CPC indicated that a combined-cycle gas facility, such as the proposed project, would be the best use of the Island End site for generation purposes and to provide thermal energy to DOMAC (id., attach. DSJ-1). Further, the Company stated that the particular characteristics of the Island End site are especially suited to the proposed project from an environmental standpoint when compared to the listed alternatives (Company Supplemental Brief at 69-70).

Finally, the Company stated that all of the selected technology alternatives were compared on the same level of net electric output, 235 MW, and thermal energy supply, 122 MMBtu/hr to the DOMAC Terminal (Exh. CPC-20, at 17). The Company indicated that all generic data requirements were obtained from the 1992 GTF report, which included availability and heat rates (id., at 9).[116,117]

CPC indicated that each alternative was assigned a projected availability rate, of which the CPC proposed project has the highest projected availability at 90 percent (Exh. CPC-20, attach. DSJ-1). The alternative technologies comparison is based on the following availability factors: gas/oil GTCC and oil-fired GTCC alternatives, 86.8 percent; CFB alternative, 83.5 percent; pulverized coal steam alternative, 81.4 percent; and residual oil steam alternative, 84.7 percent (id.). Further, the Company indicated that each alternative

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115 Although mature coal options were included in the Company's analyses, CPC stated that, due to size constraints, it does not believe that a coal-fired facility is a viable option at the proposed site (Tr. 7, at 7).

116 The Company stated that the GTF report is published annually and is appropriate for use in this analysis since it focuses solely on the New England region and is up-to-date (Exh. CPC-20, at 8-9).

117 The Company indicated that it utilized adjusted data pertaining to the proposed facility's heat rate and availability (CPC-20, at 8-9 and attach. DSJ-1, n.1).

was assigned a heat rate, of which the proposed CPC project had the lowest rate of 7,650 Btu/kW-hr (id.). The alternative technologies comparison is based on the following heat rates: gas/oil GTCC and oil-fired GTCC alternative, 8,583 Btu/kW-hr; CFB alternative, 9,770 Btu/kW-hr; pulverized coal steam alternative, 10,086 Btu/kW-hr; and residual oil steam alternative, 9,405 Btu/kW-hr (id.).

Accordingly, for purposes of this review, the municipal solid waste-fired and biomass-fired generating facilities, wind turbine facilities, nuclear fission facilities, coal gasification facilities or other technologies with an immature development status fail to address the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Board compares the proposed project to the following technology alternatives: (1) a gas/oil GTCC alternative; (2) an oil-fired GTCC alternative; (3) a CFB alternative; (4) a pulverized coal steam alternative; and (5) residual oil steam alternative. The Siting Board notes that these technology alternatives would be compatible with cogeneration. Accordingly, based on the record, the Siting Board finds that the proposed project, a gas/oil GTCC alternative, an oil-fired GTCC alternative, a CFB alternative, a pulverized coal steam alternative, and a residual oil steam alternative are comparable in terms of their ability to meet the identified need.

3. Environmental Impacts

The Company compared the alternative technologies and proposed project with respect to environmental impacts in the areas of air quality, fuel transportation, land use and fuel storage, water use, wastewater discharge, and solid waste. The Siting Board reviews the Company's analysis of environmental impacts below.

a. Air Quality

The Company asserted that the proposed project would be preferable with respect to air quality (Company Supplemental Brief at 66-67). The Company presented an analysis of the air quality impacts of alternative technologies which would be fueled by one of three types of fuel: gas, coal and oil (Exh. CPC-20). The Company stated that: (1) the gas/oil

GTCC and oil-fired GTCC alternatives were assumed to use 0.05 percent sulfur oil;[118] (2) the coal-fired alternatives were assumed to use 1.8 percent sulfur coal; and (3) the residual oil steam alternative was assumed to use one percent sulfur oil (id. at 20, RLC-2). The following chart depicts the estimated emissions of criteria pollutants[119] and CO_2 from the proposed project and each of the technology alternatives in tpy:

118 The Conditional Approval of the Company's Comprehensive Air Plans Application allows the Company to use 0.05 percent sulfur oil for up to thirty days per year for the proposed project's back-up oil supply (Exh. HO-E-1, attach. 1, at 5).

119 The National Ambient Air Quality Standards ("NAAQS") limit the total ambient levels of six pollutants, referred to as criteria pollutants: (1) SO_2; (2) PM-10, (3) NOx; (4) CO; (5) ozone and; (6) lead (Exh. HO-E-4, at 3-2). Volatile organic compounds ("VOC") are regulated as a precursor to ozone (id., at 3-4). (See Section III.C.2.a., for a further discussion of air quality).

TABLE 5

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2
(TPY)

Air Emissions (TPY)	CPC[120]	Gas/oil GTCC	Oil-fired GTCC	CFB	Pulverized Coal Steam	Residual Oil Steam
SO_2	34	102	380	1,915	1,926	975
NOx	179	209	266	1,246	1,422	1,219
PM-10	41	119	336	150	151	146
CO	85	170	183	1,079	418	244
VOC	14	27	77	50	50	41
CO_2	849,000	988,000	1,282,000	1,694,700	1,705,000	1,364,800
Lead	nil	nil	0.8	0.25	.25	<0.1

Note: The availability factors and heat rates for the proposed project and technology alternatives are set forth in Section II.B.1., above.

source: Exh. CPC-20, attach. DSJ-2

The Company stated that it assumed that each of the technology alternatives would be equipped with "state of the art" emissions control technology (Exh. CPC-20, at 11, 21). CPC stated that the gas/oil GTCC and oil-fired GTCC alternatives would include SCR for NOx control and that it assumed that the NOx emission rate for these two technology alternatives when firing natural gas would be six parts per million ("ppm") -- the same NOx emission rate as would be achieved by the proposed facility (id.; Exh. CPC-1, Table 11.2-1).

120 As noted above, the emissions for the proposed project set forth in Table 5 were based on an annual availability factor of 90 percent and 30 days per year of oil.The Siting Board notes that the emissions for the proposed facility set forth in III.C.2.a., below, were based on an availability factor of 100 percent and, therefore, are greater.

The Company explained that emissions for the gas/oil GTCC and oil-fired GTCC alternatives would be greater than emissions from the proposed project due to their greater reliance on distillate oil (Exh. CPC-20, at 21). The Company further stated that the emissions levels for the CFB alternative, pulverized coal steam alternative and residual oil steam alternative also reflected state-of-the-art pollution controls including high-efficiency SO_2 and particulate removal, and selective non-catalytic reduction ("SNCR") for NOx control (id. at 11, 21).

The record indicates that the proposed project has the lowest estimated emissions for each of the seven pollutants. See Table 5, above. Accordingly, for the purposes of this review, the Siting Board finds that the proposed project is preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives.

b. Fuel Transportation

The Company asserted that the fuel transportation impacts of the proposed project would be comparable or preferable to those of the gas/oil GTCC alternative and would be preferable to those of the other technology alternatives (Company Supplemental Brief at 64). With respect to the proposed facility, CPC indicated that the proposed site is adjacent to the primary fuel source -- the DOMAC Terminal -- and as such clearly favors an LNG-fueled GTCC facility as proposed (Exh. CPC-20, at 18-19). The Company stated that vaporized LNG would be supplied to the proposed project from an interconnecting pipeline extending from the DOMAC Terminal to the proposed facility (Exh. CPC-1, at 6.4-1). With respect to back-up fuels, CPC indicated that (1) natural gas would be transported via existing natural gas pipelines connected to the DOMAC Terminal[121] and (2) distillate oil would be transported from the Exxon petroleum products marine terminal, located adjacent to the DOMAC Terminal, via a new, 1500 foot pipeline that would be constructed adjacent to existing fuel pipelines (id. at 3.3-4, 6.4-4; Exh. CPC-20 at 18-19). See Section II.C.3.b., below, for a further discussion of fuel supply.

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121 The Company indicated that the proposed site is located adjacent to the terminus of the Algonquin Gas Transmission Company "J" lateral and Boston Gas Company distribution facilities (Exh. CPC-20, at 18).

With respect to the gas/oil GTCC alternative, the Company asserted that additional pipeline facilities would not be required for the delivery of natural gas due to the existing natural gas pipeline facilities located adjacent to the proposed site (Company Supplemental Brief at n.38, citing, Exh. CPC-20, at 18). The Company indicated that transportation of back-up distillate oil would require pipeline facilities, comparable to those required for distillate oil delivery to the proposed project (Exh. CPC-20, attach. DSJ-2). With respect to the oil-fired GTCC alternatives, the Company indicated that fuel oil transportation also would require pipeline facilities comparable to those required for distillate oil delivery to the proposed site (id.).

With respect to the coal-fired and residual oil-fired alternatives, CPC stated that fuel would be transported to the proposed site via rail or barge (Exh. CPC-20, at 19). CPC indicated that new rail facilities would be required for rail transport of coal or residual oil to the proposed site (id.). The Company estimated that the coal-fired alternatives and the residual oil steam alternative would require up to 6,700 rail cars per year (id.). The Company also indicated that new docking facilities would be required for barge transportation of coal or residual oil to the proposed site (id., at 19).

With regard to fuel transportation to the proposed project, the record demonstrates that a minimal amount of new pipeline facilities would be required for LNG and back-up fuels, and that such pipeline facilities would be located within existing industrialized property. The record further demonstrates that the gas/oil GTCC and oil-fired steam GTCC alternatives would require fuel transportation facilities comparable to those that would be required for the proposed project. In comparing the transportation impacts of the coal-fired and residual oil-fired alternatives to the proposed project, the Siting Board notes that rail transport would have continual impacts over the life of the project, specifically in relation to potential traffic interruptions and noise. The significance of impacts along the affected route, based on such factors as existing rail transport volumes, at-grade crossings, and the nature of abutting land uses have not been identified and, as such, no related impacts or mitigation strategies have been addressed by the Company. In addition, although barge transport may be an option for transporting coal or residual oil to the site, potential impacts of such transportation and new docking facilities have not been addressed. In light of the negligible impacts associated with fuel transportation for the proposed project, rail or barge transport of coal or residual oil likely would result in greater impacts.

Accordingly, based on the foregoing, for purposes of this review, the Siting Board finds that the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives with respect to fuel transportation impacts. In addition, for purposes of this review, the Siting Board finds that the proposed project would be preferable to the CFB, pulverized coal steam and residual oil steam alternatives with respect to fuel transportation impacts.

c. Land Use

CPC argued that the proposed project would be preferable to the technology alternatives with respect to land use (Company Supplemental Brief at 64-65). The Company indicated that the proposed site is 5.2 acres and that the proposed project would utilize the entire site (Exhs. CPC-20, at 20 and attach. DSJ-1; CPC-1, at 3.1-1). The Company indicated that larger sites in the vicinity of the steam host and adjacent sites to the proposed site generally were not available or were not suitable for construction of the proposed facility (see Section III.B, below) (Exhs. CPC-1, sec. 7; CPC-3, app. C).

The Company stated that land requirements for the technology alternatives, exclusive of fuel storage requirements, would be: (1) 8.5 acres for the oil/gas GTCC alternative and the oil-fired GTCC alternative; (2) 48 acres for the CFB alternative and the pulverized coal steam alternative; and (3) 40 acres for the residual oil steam alternative (Exh. CPC-20, attach. DSJ-1). The Company indicated that fuel storage would not be required on-site for the proposed facility because LNG would be available from the existing, adjacent LNG storage tanks at the DOMAC Terminal, natural gas backup would be available via existing pipeline facilities and distillate oil backup would be available from the nearby Exxon terminal (id., at 18-19). For each of the technology alternatives, the Company assumed that on-site fuel storage facilities would be required for 30 days of fuel -- 10 million gallons of oil or 60,000 tons of coal (id. at DSJ-1). Thus, the Company indicated that the gas/oil GTCC alternative, oil-fired GTCC alternative, and residual oil steam alternative each would require an additional 2.5 acres for fuel storage while the CFB alternative and the pulverized coal steam alternative each would require an additional four acres for fuel storage (id.). The Company explained that on-site fuel storage would be required for the gas/oil GTCC alternative if capacity for 60-day backup fuel storage was not available at the nearby Exxon terminal.

The record demonstrates that the proposed project would require 5.2 acres and the technology alternatives would require from 11 to 48 acres assuming on-site fuel storage. The record further demonstrates that the land area requirements of the gas/oil GTCC alternative would be reduced to 8.5 acres if on-site fuel storage were not required -- an increase of 3.3 acres over the proposed project. Given the limited size of the proposed site and lack of additional space adjacent to the proposed site or larger sites in the vicinity of the steam host, an increase in land area requirements of 3.3 acres would be significant. Accordingly, for the purpose of this review, the Siting Board finds that the proposed project is preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives with respect to land use.

d. Water Use and Wastewater Discharge

The Company asserted that the proposed project would be preferable to all of the technology alternatives with respect to water use (Company Supplemental Brief at 67-68). The Company stated that the proposed project would require 81,500 gallons per day ("gpd") for boiler makeup and steam injection for NOx control when burning oil (Exh. CPC-20, at 22 and attach. DSJ-2; Exh. CPC-6, at 10). In contrast, the Company stated that the gas/oil GTCC would require 302,000 gpd and the oil-fired GTCC would require 512,000 gpd (Exh. CPC-20, attach. DSJ-2). The Company explained that the increased water requirements over the water requirements of the proposed project result from steam injection for NOx control during both gas firing and longer periods of oil firing (id. at 22). The Company also stated that the CFB, pulverized coal steam, and residual oil steam alternatives would require 216,000 gpd due to greater boiler makeup water requirements than the proposed project (id.).

The Company further asserted that the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives but preferable to the CFB, pulverized coal steam, and residual oil steam alternatives with respect to wastewater discharge (id.; Company Supplemental Brief at 68). The Company indicated that the proposed project would generate 50,400 gpd of wastewater, the same amount of wastewater as would be generated by the gas/oil GTCC and oil-fired GTCC alternatives (Exh. CPC-20, at 22 and attach. DSJ-2). The Company further indicated that greater amounts of wastewater -- 216,000 gpd -- would be generated by the CFB, pulverized coal steam, and residual oil steam alternatives (id.).

The record demonstrates that the water requirements of the proposed project would be approximately: (1) 26 percent of the water requirements of the gas/oil GTCC alternative;[122] (2) 16 percent of the water requirements of the residual oil-fired GTCC alternative; and (3) 38 percent of the water requirements of the CFB, pulverized coal steam, and residual oil steam alternatives. Accordingly, for the purpose of this review, the Siting Board finds that the proposed project is preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives with respect to water use.

The record further demonstrates that the proposed project would generate (1) the same amount of wastewater as the gas/oil GTCC and oil-fired GTCC alternatives, and (2) 60 percent of the wastewater of the CFB, pulverized coal steam, and residual oil steam alternatives. Accordingly, for the purpose of this review, the Siting Board finds that the proposed project is comparable to the gas/oil GTCC and oil-fired GTCC alternatives and

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122 The Siting Board recognizes that the greater water requirements of the gas/oil GTCC alternative relative to the proposed project are due, primarily, to the Company's assumption that the gas/oil GTCC alternative would utilize steam injection while the proposed project would utilize dry low-NOx technology for NOx control. The record does not explain the reason for the Company's assumption of steam injection rather than dry low-NOx technology for the gas/oil GTCC alternative. However, the Siting Board notes that even if dry low-NOx technology were assumed for the gas/oil GTCC alternative, water requirements of the gas/oil GTCC alternative still would be greater than water requirements of the proposed project due to greater oil usage assumed for the gas/oil GTCC alternative.

preferable to the CFB, pulverized coal steam, and residual oil steam alternatives with respect to wastewater discharge.

e. Solid Waste

The Company indicated that the proposed project, the gas/oil GTCC alternative and oil-fired GTCC alternative would produce minimal amounts of solid waste during plant maintenance (Exh. CPC-20, at 23 and attach. DSJ-2). In comparison, the Company indicated that the residual oil steam alternative would produce 45,000 tpy of solid waste, consisting of the by-products from the removal of SO_2 from combustion exhaust (id.). The Company also indicated that both the CFB alternative and pulverized coal steam alternatives would generate 145,000 tpy of solid waste, also consisting of the by-products from the removal of SO_2 from combustion exhaust and, in addition, coal ash from the boiler and particulate removal systems (id. at 23). CPC assumed that these solid wastes would be removed from the proposed site by rail and disposed at a remote location (id.).[123]

The record indicates that the amount of solid waste produced by the proposed project, the gas/oil GTCC alternative, and the oil-fired GTCC alternative would be significantly less than the quantities produced by the CFB alternative, pulverized coal steam alternative and residual oil steam alternative. Further, the large quantities of solid waste produced by the CFB alternative, pulverized coal steam alternative and residual oil steam alternative would necessitate numerous rail trips to dispose of the waste off-site. The Siting Board notes that in most cases coal ash is shipped via the return trip of the train that transported the coal to the site. However, the record does not provide details concerning such overlap and its effect on rail transport requirements.

Accordingly, for purposes of this review, the Siting Board finds that the proposed project is comparable to the gas/oil GTCC alternative and the oil-fired GTCC alternative with respect to solid waste impacts. In addition, for purposes of this review, the Siting

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123 CPC indicated that solid waste removal would require 1,900 rail cars per year for the two coal-fired alternatives and 450 rail cars per year for the residual oil steam alternative (Exh. CPC-20, at attach. DSJ-2).

Board finds that the proposed project is preferable to the CFB alternative, pulverized coal steam alternative, and residual oil steam alternative with respect to solid waste impacts.

f. Findings and Conclusions on Environmental Impacts

With respect to air quality impacts, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to fuel transportation impacts, the Siting Board has found that the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives and preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to land use impacts, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to water use impacts, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam, and residual oil steam alternatives. With respect to wastewater discharge, the Siting Board has found that the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives, and preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

With respect to solid waste impacts, the Siting Board has found that the proposed project would be comparable to the gas/oil GTCC and oil-fired GTCC alternatives, and preferable to the CFB, pulverized coal steam, and residual oil steam alternatives.

In comparing the overall environmental impacts of the proposed project and the gas/oil GTCC alternative, the Siting Board has found that the proposed project would be would be preferable to the gas/oil GTCC with respect to air quality, land use, and water use impacts and that the proposed project is comparable to the gas/oil GTCC with respect to fuel transportation, wastewater and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project is preferable to the gas/oil GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the oil-fired GTCC alternative, the Siting Board has found that the proposed project would be preferable to the oil-fired GTCC with respect to air quality, land use, and water use impacts and comparable with respect to the oil-fired GTCC with respect to fuel transportation, wastewater and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the oil-fired GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the CFB alternative, the Siting Board has found that the proposed project would be preferable to the CFB alternative with respect to air quality, fuel transportation, land use, water use, wastewater and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CFB alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the pulverized coal steam alternative, the Siting Board has found that the proposed project would be preferable to the pulverized coal steam alternative with respect to air quality, fuel transportation, land use, water use, wastewater and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the pulverized coal steam alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the residual oil steam alternative, the Siting Board has found that the proposed project would be preferable to the residual oil steam alternative with respect to air quality, fuel transport, land use, water use, wastewater and solid waste impacts.

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the residual oil steam alternative with respect to environmental impacts.

In conclusion, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to overall environmental impacts.

4. Cost

The Siting Board evaluates the proposed project in terms of whether it minimizes cost by determining (1) if the proposed project is superior to a reasonable range of practical alternatives in terms of cost, and (2) if the proposed project offers power at a cost below purchasing utilities' avoided costs.

a. Description

Based on a comparison of the cost of the proposed project with the cost of the gas/oil GTCC alternative, oil-fired GTCC alternative, CFB alternative, pulverized coal steam alternative, and residual oil steam alternative, the Company asserted that the proposed project would be superior to the identified technology alternatives with respect to cost (Exh. CPC-20, at 14; Company Supplemental Brief at 58). In order to compare costs, CPC explained that it modelled the projected total revenue requirements[124] of each of the alternatives over a 20-year period, with an assumed in-service date of January 1, 1996 (Exh. CPC-20, at 7-8).[125]

The Company stated that it relied generally on the 1992 GTF for the cost and performance data for the generic facilities, which included: capital costs and escalators; O&M costs and escalators; fuel costs and escalators; availability; and heat rates (id. at 8-9 and attach. RLC-2). CPC indicated that in order to provide cost estimates for the alternative technologies consistent with the cost estimate for the proposed project, the Company adjusted some of the base assumptions relating to fuel prices, heat rate, and certain capital and

124 To develop a cost in dollars per megawatt hours ("$/MWH") for each option, the Company discounted the annual revenue requirements into NPV terms and developed 20-year levelized costs (Exh. CPC-20, at 7-8).

125 In projecting total revenue requirements for each alternative, CPC utilized consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. CPC-20, at 8 and attach. RLC-1).

operating costs contained in the 1992 GTF (id. at 9-12). With respect to fuel prices, the Company updated the GTF base prices to reflect actual 1992 year-to-date fuel price data for the New England region (id.).[126] In addition, the Company further adjusted the 1992 GTF cost of distillate oil to reflect the additional cost of using 0.05 percent sulfur distillate oil as assumed in the environmental analysis rather than the 0.2 percent to .3 percent sulfur distillate oil assumed in the 1992 GTF (id., at 12).

With respect to capital and operating costs, the Company stated that 1992 GTF-specified capital costs did not include costs of installing and operating certain equipment or design features of the proposed facility (id. at 10-12). CPC stated that, therefore, the 1992 GTF-specified costs were adjusted to reflect the costs of: (1) air-cooled cooling tower technology; (2) NOx emission control equipment;[127] (3) transmission network interconnection facilities; and (4) a condenser and hot water piping between the proposed facility and the thermal host (id.). CPC stated that GTF-specified operating costs were also adjusted to reflect O&M costs of the NOx emission control equipment (id. at 11-12).

Finally, the Company stated that it reduced the 1992 GTF-specified heat rates to reflect operation of the (1) air-cooled cooling tower for all technology alternatives, and (2) SCR for the gas/oil GTCC and oil-fired GTCC alternatives (id.). The Company noted that an adjustment in the 1992 GTF-specified heat rates to reflect cogeneration was not required because the thermal energy of the proposed facility would be produced without additional fuel cost or loss of power production, and thus, without a heat rate penalty (id. at n.9). Table 6, below, details the costs for the alternatives.

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126 The Company indicated that the 1992 GTF overestimated 1992 distillate oil, residual oil and coal prices and underestimated 1992 firm and interruptible gas prices (Exh. CPC-20, at 9-10).

127 CPC assumed that selective catalytic reduction SCR would be required for the gas/oil GTCC and oil fired GTCC and that SNCR would be required for the coal steam and oil steam units (Exh. CPC-20 at 11).

TABLE 6

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS
(1996$/MWH)

	CPC	Gas/Oil GTCC	Oil Fired GTCC	CFB	Coal Steam	Oil Steam
Levelized Cost (1996$/MWH[128])		$93.63	$121.41	$119.76	$127.89	$106.16
Heat Rate (Btu/kWh)	7650	8583	8583	9770	10086	9405
Availability Factor	90.0%	86.8%	86.8%	83.5%	81.4%	84.7%
Capital Costs (1996$/KW-yr[129])		$881	$881	$3,029	$3,170	$1,882

Source: Exh. CPC-20, attach. RLC-2

The Company indicated that capital costs in 1996 $/KW-yr for the proposed facility would be greater than the capital costs of the gas/oil GTCC and oil-fired GTCC alternatives and less than the capital costs of the coal-fired technology alternatives (Exh. CPC-21). The Company further indicated that the 20-year levelized cost of the proposed facility would be significantly lower than the 20-year levelized cost of each of the technology alternatives (id.).

In addition, the Company provided an analysis of the sensitivity of its cost comparison to changes in fuel prices and interest rates (Exh. CPC-20, at 13-14). Specifically, for the proposed project and each technology alternative, the Company provided (1) high and low fuel price scenarios, based on annual escalation factors of ten percent higher and ten percent

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128 The capital costs in 1996 $/kW and levelized cost were provided for the proposed facility in confidential documents.

129 In its filing, the Company estimated that the construction cost of the proposed facility would be $200 million or $851/kW in 1995 dollars (Exh. CPC-1, at 8-2). See Section III.C.3, below.

lower than the 1992 GTF-specified annual escalation factors, and (2) high and low interest rate scenarios, based on applying a 7.5 percent and 11.5 percent interest rate to all units, versus the base assumption of a 9.5 percent interest rate (id. at 13-14 and attach. RLC-1). The Company indicated that the 20-year levelized cost of the proposed project would be significantly lower than the 20-year levelized cost of each technology alternative under all alternative scenarios (Exh. CPC-21; Company Supplemental Brief at 61).

Finally, the Company provided analyses of the project costs of its proposed project relative to the avoided costs of eight Massachusetts utilities (Exh. CPC-1, at appendix C). These analyses indicated that CPC would be able to offer its power at or below all of the utilities' avoided costs (id.).

b. Analysis

With respect to the proposed project, the record indicates that the 20-year levelized cost of the proposed project would be less than the 20-year levelized cost of each of the technology alternatives under the Company's base fuel price and interest rate assumptions and under alternative fuel price and interest rate scenarios.

The Siting Board notes that the Company's cost analysis was based on 20-year levelized cost, and did not include cost estimates over a longer 25-year, 30-year or longer life that may be more favorable for considering the cost-effectiveness of the most capital-intensive technologies, notably the CFB and pulverized coal steam alternatives. Given that the costs of a generating facility are likely to be spread over a 30-year or longer period rather than a 20-year period, and that the capital costs of the CFB alternative or pulverized coal steam alternative are higher than the proposed project, the Siting Board recognizes that the use of a 30-year levelized cost could decrease the cost of CFB and pulverized coal steam alternatives relative to the proposed project. See, EEC (remand) Decision, EFSB 90-100R at 144. However, given the significant difference in the 20-year levelized costs of the proposed project versus the 20-year levelized cost of the CFB alternative and pulverized coal steam alternative, it is highly unlikely that the outcome would reflect a large enough change in levelized costs over 30-years for the proposed project relative to those of the CFB and pulverized coal steam alternatives to alter the relative cost superiority of the proposed project.

Accordingly, based on the foregoing, for the purposes of this review, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to cost.

In addition, the record indicated that CPC could provide power at a cost below seven Massachusetts utilities' avoided costs. Accordingly, the Siting Board finds that the proposed project is likely to offer power at a cost below purchasing utilities' avoided cost.

5. Reliability

a. Description

In this section the Siting Board compares the proposed project to the technology alternatives with respect to unit-specific reliability. The Siting Board notes that unit-specific reliability relates to the predictability of unit operation. As such, the Siting Board considers such factors as the anticipated availability and the reliability of the fuel supply in comparing the reliability of the proposed project with the reliability of the technology alternatives. Altresco Lynn Decision, EFSB 91-102, at 124; EEC (remand) Decision, EFSB 90-100R at 148.

CPC asserted that the proposed project would be superior to the technology alternatives in terms of reliability (Company Supplemental Brief at 70). CPC stated that it based its reliability assumptions on project availability, fuel supply, and transportation arrangements (Exh. CPC-20, at 14-16). In comparing the proposed projected to the technology alternatives on the basis of project availability, the Company acknowledged that since all of the alternatives have an expected availability of over 80 percent, all are considered highly reliable technologies (see Table 6,) (id. at 14). However, the Company did note that the proposed project's availability of 90 percent is more than three percent higher than the assumed availability of all of the technology alternatives (id.).

With respect to fuel supply and transportation, the Company asserted that, due to the proposed project's firm gas supply contract and immediate access to its gas supply, the proposed project would be superior in terms of reliability to the natural gas-fired and oil-fired alternatives but comparable to the coal-fired alternatives (id. at 15; Company Supplemental Brief at 71). The Company explained that corporate affiliates of CPC hold long-term contracts for LNG supplies and also own and operate the DOMAC facilities adjacent to the proposed site (Exh. CPC-20, at 15). The Company further explained that no new equipment would be required to provide this fuel supply to the proposed project other than a minimal amount of interconnection piping (id.). In addition, the Company noted that the DOE has stated that DOMAC LNG supply arrangements provide a "reliable and secure source of supply" for the United States (id.). In comparison, the Company stated that the fuel supply assumed for the gas/oil GTCC alternative -- 10 months of interruptible gas with a 60-day distillate oil backup -- would be subject to regular curtailment, primarily during cold weather periods (id.).[130] The Company added that due to uncertainties associated with interruptible gas supplies, the gas/oil GTCC likely would not be financeable (id. at 16).

b. Analysis

The record demonstrates that the availability of the proposed project would be 90 percent. The record further demonstrates that the Company has contracted for a firm, long-term fuel supply with a corporate affiliate, ensuring that the fuel supply for the proposed project would be limited in its volatility. See Section II.C., below.

In comparing the reliability of the proposed project to the reliability of the gas/oil GTCC alternative, the Siting Board notes that the availability factor for the gas/oil GTCC alternative is assumed to be 86.8 percent, 3.5 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the gas/oil GTCC alternative in annual facility operation does not represent a significant difference for purposes of this review in and of itself. However, the Siting Board recognizes that the assumed natural gas

130 In addition, the Company noted that the price of spot gas is highly volatile (Exh. CPC-20, at 16).

supply of the gas/oil GTCC alternative -- 10 months of interruptible gas -- would not be a realistic supply option. A facility that has an assured fuel supply for only two months would not be financeable. The Siting Board notes that a more realistic fuel supply for a gas/oil GTCC facility would be firm gas for at least ten months with an interruptible gas supply and oil back-up for a maximum of 35 days. See, Altresco Lynn Decision, EFSB 91-102, at 142-144; West Lynn Decision, 22 DOMSC at 73; NEA Decision, 16 DOMSC at 379-380, 398. Therefore, taken together, both the lower availability and unrealistic fuel supply renders the oil/gas GTCC alternative a potentially unreliable energy source. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability.

In comparing the proposed project to the oil-fired GTCC alternative, the Siting Board notes that the record indicates that the availability factor of the oil-fired GTCC alternative would be comparable to the gas/oil GTCC alternative. The record provides no evidence that reliance on distillate oil would present fuel supply or transportation problems. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the oil-fired GTCC alternative with respect to reliability.

With regard to the CFB alternative, the record indicates the likely availability factor would be 83.5 percent, 7.2 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the CFB alternative in annual facility operation, but does not represent a significant reliability difference for purposes of this review. Further, as the Company noted, coal, a domestic fuel source does not raise reliability concerns. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the CFB alternative would be comparable with respect to reliability.

With regard to the pulverized coal steam alternative, the record indicates the likely availability factor would be 81.4 percent, 9.5 percent lower than the availability factor of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the pulverized coal steam alternative in annual facility operation, but does not represent a significant difference for purposes of this review. Further, as noted above, the fuel supply and transportation arrangements would be comparable to the CFB alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the pulverized coal steam alternative would be comparable with respect to reliability.

With regard to the residual oil steam alternative, the record indicates the likely availability factor would be 84.7 percent, 5.9 percent lower than the availability of the proposed project. Such a difference in availability of the two technologies indicates that the proposed project would be slightly preferable to the residual oil steam alternative in annual facility operation, but does not represent a significant difference for purposes of this review. In addition, the fuel supply and transportation arrangements would be comparable to the oil-fired GTCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the residual oil steam alternative with respect to reliability.

Accordingly, the Siting Board finds that the proposed project would be comparable to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to reliability. Further, the Siting Board finds that the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

In City of New Bedford, the Court stated that "the statute mandates that the [Siting C]ouncil balance environmental harm that would be caused by a new power plant against the other statutory objectives -- providing a necessary energy supply at the lowest possible cost." 413 Mass. at 485. In addition, the Court stated "[t]he statutory mandate, however, requires that the energy the facility will supply is necessary for the Commonwealth; that the supply of the energy involves a minimum impact on the environment; and that such energy is supplied at the lowest possible cost. Thus, the statutory balance involves weighing minimum environmental impact and cost." Id. at 486. In addition, the Court stated that the Siting Council would need to explicitly state that it was approving a project with greater environmental impacts than alternatives on the basis of a determination that other factors outweighed those environmental impacts. Id. at 490.

In Section II.B.1., above, the Siting Board noted that, in order to establish that a proposed project is preferable to technology alternatives in its ability to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board would require the applicant to establish 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.

In Sections II.B.3., II.B.4., and II.B.5., above, the Siting Board has analyzed the record, by comparing the proposed project against generating technology alternatives that have been determined capable of meeting the identified need, and on the basis of their specific impacts on the environment, costs and reliability.

In comparing the environmental impacts of the proposed project to the environmental impacts of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to environmental impacts.

In comparing the costs of the proposed project to the costs of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC, oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to cost.

In comparing the reliability of the proposed project to the reliability of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the gas/oil GTCC alternative with respect to reliability, and the proposed project would be comparable with respect to the oil-fired GTCC, CFB, pulverized coal steam and residual oil steam alternatives with respect to reliability.

As noted above, the proposed project is preferable to the gas-oil GTCC alternative with respect to environmental impacts, cost and reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the gas-oil GTCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the oil-fired GTCC alternative, as noted above, the proposed project is preferable to the oil-fired GTCC alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the oil-fired GTCC alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the oil-fired GTCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the CFB alternative, as noted above, the proposed project is preferable to the CFB alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the CFB alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the CFB alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the pulverized coal steam alternative, as noted above, the proposed project is preferable to the pulverized coal steam alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the pulverized coal steam alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the pulverized coal steam alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With regard to the residual oil steam alternative, as noted above, the proposed project is preferable to the residual oil steam alternative with respect to environmental impacts and cost. Further, the proposed project is comparable to the residual oil steam alternative with respect to reliability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the residual oil steam alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

Accordingly, based on the foregoing, the Siting Board finds that the Company has established that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

C. Project Viability

1. Standard of Review

The Siting Board determines 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. Altresco-Lynn Decision, EFSB 91-102, at 129-130; Enron Decision, 23 DOMSC at 89; NEA Decision, 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 the 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 actual or likely power sales agreements. Altresco-Lynn Decision, EFSB 91-102, at 129-130; Enron Decision, 23 DOMSC at 89; Altresco-Pittsfield Decision, 17 DOMSC at 378.

Here, CPC argued that the proposed project meets all of the Siting Board's requirements related to project viability (Company Brief at 100).

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project would actually go into service as planned. Here, CPC stated that it expects a significant interest in equity participation in the proposed project based on preliminary discussions between the Company and potential investors (Exh. CPC-1, at 6.1-1). The Company stated that such equity participation and other key factors including the alternative of internal funding from its parent organization, Cabot LNG Corporation, and prudent structuring of its fuel contract with DOMAC, would combine to alleviate debt financing requirements (id. at 6.1-1, 6.1-2). The Company asserted that, as in past Siting Council reviews regarding project financing strategies, the proposed project exhibits a favorable debt coverage ratio, strong financial strength and experience of the project participants, flexibility with the proposed equity financing plan and a well-defined marketing plan, all of which provide assurance that the proposed project is reasonably likely to be financed so that the project will actually go into service as planned (Company Brief at 82, citing, Enron Decision, 23 DOMSC at 98; EEC Decision, 22 DOMSC at 300).

The Company asserted that CPC and its affiliates have financial strength and extensive energy-project-financing experience (id. at 84-85; Exh. HO-B-7). The Company stated that Cabot Corporation has developed, financed, and currently operates several cogeneration projects including the Berre carbon black facility near Marseilles, France which contains a 20 MW cogeneration plant, and a similar but smaller cogeneration plant -- associated with a Cabot carbon black plant -- located in Altona, Australia, which generates 16 MW (Exh. HO-B-7). The Company added that two other projects are in the planning stages, the Canal Plant in Franklin, LA and the Sarnia Plant in Ontario, Canada (id.). The Company stated that Cabot Corporation is a specialty chemical and energy firm, established in 1882 with annual sales currently approaching $2 billion (Exhs. CPC-1, at 1.2-1, App. A; CR-20).

The Company further stated that it had performed financial analyses of the proposed project to determine the project's financial viability (Exhs. HO-PV-6; HO-PV-27). The Company stated that its analyses were based on conservative assumptions relating to the price and amount of power sold, dispatch factor, capacity factor, heat rate, the cost of fuel and other important variables that affect project finances (id.; Exhs. HO-B-10; HO-B-11).[131]

[131] The Company stated that it assumed that the proposed project's status would be dispatchable and operate at a 90 percent capacity factor, and added that the actual dispatch level would negligibly affect the proposed project's financial returns

Based on its preliminary discussions with financial lenders, CPC stated that a minimum annual average debt coverage ratio of 1.4 would be required to finance the proposed project on favorable terms, and added that the lowest debt coverage ratio for any year would likely need to be greater than 1.3 (Exh. HO-PV-5).

The Company added that, based on the results of its financial analyses, the proposed project could comfortably meet the minimum debt coverage ratios required for acceptance by the financial community (Exhs. HO-PV-6; HO-PV-27).

CPC stated that several entities have expressed an interest in equity participation, including the Engineering, Procurement, and Construction ("EPC") contractor, and the O&M contractor (Exh. HO-PV-3). The Company asserted that the inherent cooperation between CPC and the thermal host, as well as the project location are attributes that make the proposed project attractive to outside investors (id.). CPC stated that preliminary feedback from lenders indicated that a realistic debt/equity ratio would be approximately 80/20, if the proposed project were to be financed on a non-recourse basis (id.). The Company also stated that Cabot Corporation could finance the proposed project internally, and that under that approach the debt/equity ratio would depend on Cabot Corporation's debt/equity ratio and its willingness to advance equity funding to Cabot LNG Corporation to finance the proposed project (id.).

CPC stated that it would retain flexibility with respect to whether the project would be financed on a non-recourse, project finance or internally funded basis (Exh. HO-PV-7). CPC listed several factors that would affect the final selection of the particular financing option including: (1) non-recourse financing terms available at the time of commencement of construction; (2) projected financial returns after the majority of power is sold; (3) financial benefits from opportunities to sell equity interest in the project and timing decisions with regard to such sales; and (4) Cabot Corporation's other investment opportunities and capital budgets (id.). CPC noted that Cabot LNG Corporation, CPC's parent company, is providing funding for the development phase of the project which includes permitting, conceptual

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(Exh. HO-PV-2).

design, and securing project agreements (power purchase, fuel supply, thermal host, site lease, etc.) (Exh. HO-PV-2). CPC added that Cabot LNG Corporation is arranging for construction financing and would, if the project is to be internally funded, arrange for permanent financing (id.).

The Company stated that it plans to market the electric power from the proposed project to New England electric utilities that are part of NEPOOL (Exh. HO-MN-1; Tr. 6, at 25). CPC stated that it has been communicating with all private and public purchasers of wholesale electric power in New England, approximately 100 entities, and added that this communication has consisted of a description of the proposed project and a preliminary offer sheet (Exh. HO-MN-1).[132] The Company provided analyses of the cost of the proposed project's output relative to the avoided costs of eight Massachusetts utilities which may purchase power from the plant (Exh. CPC-1, Appendix C). The Company stated that these analyses indicated that CPC would be able to offer its power at a price below the utilities' avoided costs (id.).[133] See Section II.A.4., above.

The record provides no indication that any of the proposed project's output has been sold to date. Nevertheless, CPC has identified a range of options for project financing, including possibilities for equity participation by project contractors and internal funding by Cabot LNG Corporation. CPC also has considered a number of scenarios which address the sensitivity of project finances to the price and amount of power sold, fuel prices, and other important variables. CPC's analyses indicate that CPC would be able to offer power at or below utilities' avoided cost -- a necessity in signing long-term PPAs.

The Siting Board notes that a proponent's prospects for obtaining outside or non-recourse project financing are usually dependent upon and proportional to the amount of power sales which have been achieved relative to the total power output capability of the

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132 CPC also stated that it has responded to several RFP's, but indicated that, to date, no contracts have been awarded as a result thereof (Exh. HO-MN-1).

133 The Company compared the NPV of its total costs with the NPV of the purchasers avoided costs, and expressed the ratio as a percentage of avoided costs (Exh. CPC-1, Appendix C).

proposed project. Here, while CPC has developed a strong plan for financing the proposed project, the Siting Board notes that one key assurance to obtaining project financing -- signed PPAs, for a significant majority of the proposed facility's output -- is missing from an otherwise well developed financing plan.

In Section II.A.5., above, the Siting Board was unable to find need for the proposed project prior to the year 2000. Therefore, the Siting Board required CPC to submit, within four years, signed and approved PPAs for at least 75 percent of the proposed projects' electric output in order to receive final approval. The Siting Board notes that in light of the uncertainty of need in the early years of proposed facility operation, it may be difficult for the Company to market a sufficient portion of its capacity to be financiable within the proposed time frame. Nevertheless, if CPC complies with the condition regarding PPAs, the Company will be able to ensure that the proposed project is financiable.

Based on the foregoing, the Siting Board finds that upon compliance with the condition in Section II.A.5, above, CPC will have established that its proposed project is financiable.

b. Construction

In considering a proponent's construction strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Here, CPC indicated that it has selected Fluor Daniel, Incorporated ("FDI") as the EPC contractor (Exh. HO-PV-11). The Company provided an executed contract between CPC and FDI dated January 27, 1992 to provide EPC services for the proposed project (Exh. HO-PV-29).

CPC indicated that FDI would be responsible for complete design, engineering, procurement, construction, startup and performance testing of the proposed facility (id.; Exh. CPC-1, at 6.2-1). The Company further indicated that the contract terms ensure timeliness of completion and construction quality, with a bonus for early completion, penalties for late completion, a fixed price, facility performance guarantees, and liquidated damages for nonperformance (id.). CPC stated it selected FDI based on experience,[134] working knowledge of the proposed project, and favorable contract terms (Exh. HO-PV-11).

In regard to the facility site and access arrangements, CPC stated that MassGas, Inc. owns the proposed project site and is willing to make it available to CPC for the proposed project (Exh. HO-PV-14). CPC provided a copy of a signed 30-year ground-lease agreement with MassGas, Inc. effective January 31, 1992 (id.). Finally, the Company provided to the Siting Board an interconnection study prepared by BECo[135] which identified a total of five interconnection options -- the preferred option and four alternatives -- and the associated costs relative to each option (Exh. HO-PV-15).

In the past, the Siting Board 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 would be able to perform as expected. Enron Decision, 23 DOMSC at 103; Altresco-Pittsfield Decision, 17 DOMSC at 380. Here, CPC has submitted a signed EPC contract. The contract includes a number of advantageous provisions, including a fixed price provision which will minimize financial risk to CPC, and a bonus/penalty provision, to ensure timeliness and quality of construction. In addition, the record indicates that FDI has considerable experience in constructing gas-fired combined-cycle projects. Further, the record indicates that CPC has entered into a signed 30-year ground lease agreement with MassGas, Inc. Therefore, the Siting Board finds that the Company has established that the proposed project is likely to be constructed within applicable timeframes.

However, although the Company has provided an interconnection study prepared by BECo, it has not provided evidence of a signed interconnection agreement with BECo

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134 The Company stated that FDI is presently providing technical services to CPC in support of project development and permitting issues as related to the proposed facility (Exhs. CPC-1, at 2.3-1; HO-PV-30). The Company added that FDI has completed over 60 combustion turbine projects, which together, produce approximately 8,000 MW of electrical power (id.).

135 The Company stated that it funded BECo's interconnection study (Exh. HO-PV-15).

enabling transmission access. Failure to gain access to the regional transmission system would prevent the proposed project from providing energy to the state and the region. The Company has not provided a written explanation as to why such an interconnection agreement is not yet available. However, if CPC provides evidence of such an agreement, the Company will be able to establish that its proposed project is likely to be capable of meeting performance objectives. Therefore, the Siting Board requires CPC to provide the Siting Board with a signed copy of an interconnection agreement between CPC and BECo as evidence of the proposed project's access to the regional transmission system.

Accordingly, based on compliance with the above condition that the Company provide the Siting Board with a signed copy of the agreement between CPC and BECo for provision of the proposed project's access to the regional transmission system, the Siting Board finds that CPC will have established that its proposed project is likely to be constructed within applicable timeframes and be capable of meeting performance objectives.

The Siting Board has found that, upon compliance with the condition relative to power sales in Section II.A.5, above, CPC will have established that its proposed project is likely to be financiable. The Siting Board has also found that, upon compliance with the above condition relative to the assurance of access to the regional transmission system, CPC will have established that its proposed project is likely to be constructed within applicable time frames and be capable of meeting performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, CPC will have established that its proposed project meets the Siting Board'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 Board 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. Altresco-Lynn Decision, EFSB 91-102, at 139; Enron Decision, 23 DOMSC at 106;

Altresco-Pittsfield Decision, 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 detailed pursuant to contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of actual or likely power sales agreements. Altresco-Lynn Decision, EFSB 91-102, at 138; Enron Decision, 23 DOMSC at 106; Altresco-Pittsfield Decision, 17 DOMSC at 381-382.

CPC stated that it has selected Mission Operation and Maintenance, Incorporated ("MOMI") as the O&M contractor responsible for the proposed project (Exh. HO-PV-16). CPC provided documentation indicating that MOMI is the operating arm of the Mission Energy Company -- a wholly owned subsidiary of Southern California Edison Company (Exh. HO-B-5). The Company indicated that MOMI currently operates nine gas-fired cogeneration plants representing nearly 1.15 billion watts of electrical supply (id.). The Company provided the Siting Board with an executed O&M contract between CPC and MOMI dated January 24, 1992, containing a 10-year contract term and options for two five-year extensions (Exh. HO-PV-33).

The Company stated that the O&M contract includes pricing terms structured to ensure that MOMI will operate the proposed facility in a safe, reliable, and efficient manner over the duration of the contract (id.; Exh. HO-PV-35). The Company stated that the performance fee term is based on several factors including plant availability, heat rate degradation, net power output degradation, safety practices, and maintenance of community relations (Exh. HO-PV-33; Tr. 6, at 27-28). The Company added that, with renewal options, the O&M agreement could be extended for the duration of likely power sales agreements provided satisfactory results were being achieved (Exh. CPC-1, at 6.3-2).

In the past, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreements. Altresco-Lynn Decision, EFSB 91-102, at 139; Enron

Decision, 23 DOMSC at 107; Altresco-Pittsfield Decision, 17 DOMSC at 382. Here, CPC has provided an executed O&M agreement with MOMI, a qualified vendor, complete with bonus, penalty, and incentive provisions similar to those reviewed and approved in prior Siting Board decisions.

Accordingly, the Siting Board finds that CPC has established that its proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreement.

b. Fuel Acquisition

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

Here, CPC provided a copy of a signed 20-year contract with its affiliate, DOMAC, dated January 30, 1992, to supply all the natural gas requirements of the proposed project (Exhs. HO-PV-38; HO-PV-18, attach.). The Company added that pursuant to the gas purchase contract with DOMAC, a 365-day-per-year firm supply of LNG would be provided from the DOMAC terminal (Exh. HO-PV-18, attach.).[136]

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136 The Company stated, however, that the gas purchase contract allows DOMAC the option of providing either natural gas or distillate fuel oil as substitutes for the LNG (Tr. 3, at 16-17). Specifically, CPC's witness, Mr. Jones, noted that Distrigas has agreed to a price for LNG based on it retaining an ability to switch fuels for 30 days per year, allowing it to sell the LNG to other markets for the same duration, and added that such fuel switching would typically be done during the winter season when demand is high (id.). Mr. Jones added that the Company had requested the necessary approvals which would allow 30 days of oil firing primarily because lenders will typically require backup fuel for approximately 30 days to allow essential fuel capability for enough of the year to enable a facility to operate and remain viable, thus servicing the debt (id.).

The Siting Board notes that the record indicates that fuel substitution shall be consistent with applicable environmental permits (Exh. HO-PV-18, attach.). We further note that the Conditional Approval of CPC's Comprehensive Air Plans Application allows utilization of low sulfur fuel oil (0.05 percent sulfur) for a

The Company stated that, since the proposed project would be located adjacent to the DOMAC Terminal, there would be no need for fuel transportation by an outside pipeline/distribution company (Exh. CPC-1, at 6.4-1). CPC stated that the gas to be supplied by DOMAC would be LNG that is imported from Algeria[137,138] by Distrigas Corporation ("Distrigas"), a sister company of DOMAC (id.). CPC added that the LNG is then vaporized at the DOMAC Terminal (id.; Exh. CPC-7, at 2). CPC added that, other than the short interconnection piping which would be located on the DOMAC Terminal property and extend to the proposed site adjacent to the DOMAC Terminal, no new equipment would be required to provide the vaporized LNG to CPC (Exhs. CPC-1, at 6.4-1; CPC-2, at 2).

The Company stated that the DOMAC Terminal has received LNG cargos and in turn sent out LNG in vapor and liquid form since it went into operation in 1971 (Exhs. CPC-7, at

maximum of 30 days only in emergency situations, i.e., when both vaporized LNG and natural gas are not available. Therefore, the Siting Board expects that fuel oil substitution for LNG or natural gas for economic reasons will not take place.

137 CPC acknowledged that a degree of political instability exists in Algeria, but stated that, because Algeria is not a significant producer of oil and needs its stable gas trade to earn hard currency, it would be unlikely that any such political instability in Algeria would bring about a disruption in LNG exports (Exh. HO-PV-36). CPC stated that all the viable political entities appear committed to economic reform, and added that expanded gas exports would be one way to facilitate such reform (id.). CPC noted that since the current Algerian political crisis is largely an outgrowth of an economic crisis, it would be unlikely that a ruling entity (of whatever political persuasion) would disrupt LNG exports, as such an action would cause an immediate drop in export revenues, thus compounding the economic problems rather than improving them (id.). CPC added that Algeria has supplied LNG to France, Spain, Italy, Great Britian, and Belgium in addition to the United States for over twenty years (id.).

138 CPC indicated that, based on Distrigas' track record of gas imports, the DOE found that Distrigas' import arrangements provide a "reliable and secure source of supply" for the United States (Exh. CPC-1, at 6.4-2). CPC also noted that Distrigas is continuing negotiations for LNG supplies from Nigeria where an LNG project is projected to commence deliveries in 1995-1996 (id.).

3; HO-PV-21).[139] CPC stated that Distrigas would be responsible for importing the DOMAC volumes to the DOMAC Terminal, where it would be received and vaporized by DOMAC for direct delivery to CPC (Exhs. CPC-1, at 6.4-1; CPC-2, at 2). The Company stated that the deliverability of the LNG to the DOMAC Terminal is backed by LNG reserves of approximately 110 trillion cubic feet owned by Sonatrach, an Algerian oil and gas company (Exh. CPC-1, at 6.4-1). CPC further asserted that the recent acquisition of an LNG carrier by an affiliated company, Cabot LNG shipping, further enhances the reliability and operating flexibility of the DOMAC LNG supply (id., at 6.4-2; Exh. CPC-7, at 4-7).

Regarding fuel costs, the Company stated that there would be no pipeline transportation charges because the proposed project would be located adjacent to the DOMAC Terminal (Exh. CPC-1, at 6.4-3). CPC indicated that pricing terms of the gas purchase contract with DOMAC provide for a low initial fuel cost and stable price certainty throughout the life of the proposed project (Exh. HO-PV-18, attachment). CPC also indicated that its gas purchase contract with DOMAC contains provisions which would allow fuel pricing to be adjusted based on industry trends (id.; Exh. HO-PV-39). The Company added that it would have no minimum take requirements under the gas purchase contract with DOMAC (Exh. CPC-1, at 6.4-2).

CPC stated that in the unlikely event that DOMAC was temporarily unable to supply vaporized LNG to the proposed facility under the terms of the 365-day fuel contract, DOMAC would, except under force majeure conditions, provide back-up fuel -- natural gas, or distillate oil (id., at 6.4-4; Exh. HO-PV-18, attach.). With respect to the natural gas back-up option, the Company stated that the proposed project is centrally located in relation to Boston Gas Company's integrated distribution system which provides access to pipelines of both Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company, as

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139 The Company noted that DOMAC receives and resells such LNG in both liquid and gaseous form under terms and conditions approved by the FERC (Exh. CPC-1, at 6.4-1). CPC asserted that Sonatrach, an Algerian oil and gas company, and DOMAC's supplier, has an excellent record of reliability, and stated that Sonatrach has never interrupted deliveries to the DOMAC Terminal (id. at 6.4-1, 6.4-2).

well as Boston Gas Company's LNG, synthetic natural gas, and propane air facilities (Exh. CPC-1, at 6.4-4). CPC added that because the Boston Gas Company pipeline system connects directly into the DOMAC facility, these entities would all be potential sources of alternate gas supplies (id.).

Regarding a distillate fuel oil back-up option, the Company stated that a light distillate fuel -- such as jet fuel -- would be supplied by DOMAC and delivered as necessary from the nearby Exxon Terminal (Exhs. HO-PV-18, attach.; HO-PV-23; Tr. 3, at 16-17). The Company added that the distillate fuel could be stored off-site in existing tanks at the Exxon Everett Marketing Terminal adjacent to the DOMAC Terminal, approximately 1500 feet from the project site (Exh. CPC-1, at 6.4-4). However, the Company also indicated that it is negotiating an agreement directly with Exxon to supply the proposed project with back-up fuel oil (Exh. HO-PV-23).

In reviewing a project's fuel acquisition strategy, the Siting Board necessarily focuses on the project's primary fuel supply. However, back-up fuel supplies and/or contingency plans for interruptions in primary fuel supplies also have consistently been considered by the Siting Board. Altresco Lynn Decision, EFSB 91-102, at 143-144; Enron Decision, 23 DOMSC at 118; Altresco-Pittsfield Decision, 17 DOMSC at 384-389.

Here, CPC has described a primary fuel supply option and two back-up fuel supply options for the proposed facility. In regard to the primary gas supply, CPC is in possession of a signed gas purchase contract with DOMAC, and has articulated a reasonable long-term primary fuel supply plan. The location of the proposed project adjacent to the fuel supply is advantageous -- no new equipment will be required to deliver fuel to the proposed project other than a minimum amount of interconnection piping. Further, the fuel supply is likely to be competitively low-cost due to the fuel supply contract terms for (1) a low initial fuel price, and (2) stable prices throughout the life of the proposed project.

With respect to back-up fuel supply plans, the Company would utilize natural gas or distillate oil. The Siting Board notes that the location of the proposed project also is advantageous with respect to each of the back-up fuel supply options and further notes that pipeline interconnects -- terminating at the proposed facility -- would enable delivery of each option. The gas purchase contract with DOMAC provides that DOMAC would be responsible to supply natural gas to the proposed project in the event that it was unable to supply vaporized LNG. However, the record is unclear regarding the entity responsible for supplying back-up fuel oil. Although the gas purchase contract with DOMAC also provides that DOMAC would be responsible to supply distillate oil, the Siting Board notes that the Company is negotiating a back-up fuel supply agreement with Exxon. The Siting Board also notes that Exxon could in the future transfer ownership rights of its fuel oil storage tanks to another entity. Therefore, the Siting Board requires that CPC provide a copy of the contract or any other agreement between the Company and Exxon or any of Exxon's successors, transferees or assigns, regarding the supply of distillate fuel oil to the proposed project.

Accordingly, based on the foregoing, the Siting Board finds that upon compliance with the aforementioned condition, CPC will have established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the likely term of project PPAs.

The Siting Board has found that CPC has established that (1) the proposed project is likely to be operated and maintained in a manner consistent with reliable performance over the likely term of project PPAs, and (2) upon compliance with the aforementioned condition, its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the likely term of project PPAs. Accordingly, the Siting Board finds that, upon compliance with the aforementioned condition, CPC will have established that its proposed project meets the Siting Board's second test of viability.

4. Conclusions on Project Viability

The Siting Board has found that, upon compliance with the conditions in Sections II.A.5, II.C.2, and II.C.3, above, CPC will have established that its proposed project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and is likely to operate and be a reliable, least-cost source of energy over the life of its PPAs.

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, CPC will have established that its proposed project is likely to be a viable source of energy.

III. ANALYSIS OF THE PROPOSED FACILITIES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. Further, G. L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Board requires a 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. Altresco Lynn Decision, EFSB 91-102, at 157; 1993 BECo Decision, EFSB 90-12/90-12A at 27.

A. Description of Proposed Facilities

CPC proposes to construct a 235-MW gas-fired, combined-cycle cogeneration facility within the IEIP which is located in the City of Everett and bordered, generally, by the Island End River, the Mystic River, Routes 16 and Route 66 (Exh. CPC-1, at 1.1-1, 3.3-1). The proposed site is currently occupied by a vacant warehouse and truck loading areas and is owned by MassGas, Inc., an affiliate of Cabot (id. at 1.1-1, 3.1-1). The proposed site contains 5.2 acres and is surrounded by industrial uses including the DOMAC LNG Marine Terminal and an unused rail spur to the northwest, a warehouse to the northeast, and a cement storage facility and sand and gravel operation to the south (id.). See Figure 1.

The major components of the proposed project consist of: (1) a 155 MW high temperature combustion turbine-generator with dry low-NOx combusters; (2) an HRSG; (3) an 80 MW steam turbine-generator; (4) an SCR system; (5) an air-cooled condenser; (6) a turbine air inlet chiller;[140] and (7) a 240-foot exhaust stack (id. at 1.3-1, 3.3-4). Additional components include a 345 kV gas-insulated substation, and an ammonia storage tank (id.). Relatively low temperature exhaust steam would be converted to hot water and piped to the DOMAC Terminal where it would be utilized to vaporize LNG (id. at 2.2-4).[141] Electricity output would be transmitted to the Boston Edison Mystic Station substation via an approximately one-half mile, underground, 345 kV transmission line (id. at 3.1-2, 3.3-5).

The primary fuel for the proposed facility would be LNG with natural gas or low-sulfur, light distillate fuel oil as back-up (id. at 1.4-1). DOMAC would supply (1) vaporized LNG via a pipeline from the DOMAC Terminal, or (2) equivalent volumes of natural gas via existing pipeline facilities connected to the DOMAC Terminal if vaporized LNG were not available (id. at 3.3-4). Back-up fuel oil would be supplied to the proposed facility via a pipeline from an existing Exxon terminal which is located adjacent to the DOMAC Terminal (id. at 1.4-1).[142]

The proposed facility would cost approximately $200 million in 1995 dollars (Exh. CPC-2, at 2.2-11).

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140 The Company noted that power output would increase with lower temperatures and that, at times when New England is experiencing summer capacity shortages, the turbine inlet chiller would be operated to cool inlet air and thus increase power output (Exhs. CPC-2, at 7.3-2; CPC-3, at 2-3). CPC also noted that air emissions would increase with lower inlet air temperatures (id.).

141 The Company indicated that, currently, LNG is vaporized by use of gas-fired boilers which require approximately 1.8 percent of the vaporized output of the DOMAC Terminal (Exh. CPC-2, at 2.2-1).

142 The Company noted that Exxon has agreed to (1) supply the proposed facility with fuel oil from its existing inventory for short periods of times, and (2) enter into an agreement to store fuel oil in its existing tanks if it is needed for longer periods (Exh. CPC-1, at 1.4-1). See Section II.C.3. above.

B. Site Selection Process

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Altresco Lynn Decision, EFSB 91-102, at 157; 1993 BECo Decision, EFSB 90-12/90-12A at 27; NEA Decision, 16 DOMSC at 381-409. In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it 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. Altresco Lynn Decision, EFSB 91-102, at 157; 1993 BECo Decision, EFSB 90-12/90-12A at 27; Berkshire Gas Company (Phase II), 20 DOMSC 109, at 148-149, 151-156 (1990) ("1990 Berkshire Decision"). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.[143] Altresco Lynn Decision, EFSB 91-102, at 157-158; 1993 BECo Decision, EFSB 90-12/90-12A at 28; NEA Decision, 16 DOMSC at 381-409. In past decisions, the Siting Board has not required a noticed alternative site in cases involving proposals to construct cogeneration facilities if the cogeneration proponent (1) had a steam sales agreement with existing steam purchaser(s) sufficient to qualify it for QF status, and (2) had a proposed site fully within the property

[143] When a facility proposal is submitted to the Siting Board, 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 Board's review. In reaching a decision in a facility case, the Siting Board can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Board, 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.

boundaries of the principal steam host. Altresco Lynn Decision, EFSB 91-102, at 158; EEC Decision, 22 DOMSC at 315; MASSPOWER Decision, 20 DOMSC at 382.

However, the Siting Board notes that proposed sites or routes located in the coastal zone as defined under the Massachusetts Coastal Zone Management ("CZM") program and the Coastal Zone Management Act, 16 U.S.C. § 1453, are subject to additional regulatory requirements.[144] The Siting Board is the designated energy facilities siting agency under the CZM program pursuant to 980 C.M.R. 9.01ff. These regulations implement the CZM program as adopted by the Secretary of Environmental Affairs under G.L. c. 21A, §§ 2, 3, and 4.

Under the Siting Board's Coastal Zone Facility Site Selection, Evaluation, and Assessment regulations, when a facility is proposed for coastal siting, the petitioner must "propose, evaluate and compare at least one alternative site." 980 C.M.R. 9.02(1)(a). Further, when a facility proposed for coastal siting is not a coastally dependent energy facility see, 980 C.M.R. 9.01(2), the alternative site to be proposed, evaluated and compared "shall be inland of the coastal zone." 980 C.M.R. 9.02(1)(a). Any alternative site "shall be reasonably determined and demonstrated to be capable of development and licensing or approval by all federal, state, regional and local agencies". Id. The site evaluation and comparison must "include a justification of the necessity for, or advantage of, coastal siting along with an explicit definition of the process developed to compare alternative sites." Id.[145]

In the sections below, the Siting Board reviews the Company's site selection process, including CPC's development and application of siting criteria as part of its site selection process, and the consistency of the Company's proposal with the Coastal Zone Facility regulations.

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144 In the instant case, the site proposed by the Company is located in the coastal zone as defined by the CZM Program and the CZM Act and regulations (Exh. CPC-1, at 9.4-1). See, 16 U.S.C. § 1453; 980 C.M.R. 9.00.

145 These requirements apply only to proposed sites located in the coastal zone as defined under the Massachusetts CZM program.

2. Development of Siting Criteria

The Company indicated that the thermal needs and fuel supply opportunities of the DOMAC Terminal would offer significant benefits to a cogeneration project as compared to a typical thermal host (Exhs. CPC-1 at 7.1-1, 7.1-2; HO-S-1). Specifically, the Company stated that DOMAC's ability to utilize hot water rather than low or medium pressure steam would allow a cogeneration project to supply thermal energy to DOMAC without additional fuel cost or loss of power production (Exhs. CPC-1 at 5.2-2, 5.2-3; HO-S-1). In addition, CPC stated that DOMAC's large thermal demand would allow for construction of a cogeneration project with good economies of scale and that DOMAC would make fuel available without the need for natural gas transportation by a pipeline or local distribution company (Exh. CPC-1, at 7.1-1). Therefore, the Company stated that the proposed project was conceived to serve the thermal needs of the DOMAC terminal and that CPC focussed its initial site selection process on sites within the immediate vicinity of the DOMAC Terminal (Exhs. CPC-1, at 7.2-1; HO-S-1; HO-S-2).

The Company noted that the DOMAC Terminal and surrounding area is located within the boundary of the Massachusetts coastal zone, and that, therefore, any facility proposed in this area would be subject to state coastal zone regulations (Exh. CPC-2, at 3.2-1).[146] In reviewing CPC's initial site selection process, the CZM program office noted its concern that the Company did not thoroughly address whether use of the proposed site for a cogeneration facility was consistent with all policies of the CZM program (Exh. CPC-6, at 7). In response, the Company supplemented its original site selection and evaluation study to incorporate CZM program concerns (id. at 7-8).

a. Description

The Company asserted that its site selection process ensured that a clearly superior site

[146] The Company indicated that the coastal zone boundary extends approximately three quarters of a mile inland from the Mystic River (Exh. CPC-6, at 6). Compliance of the proposed facility with all policies of the CZM program is discussed in Section III.C.2.d., below.

had not been overlooked or eliminated from consideration (Company Brief at 105). In conducting its site selection process, the Company indicated that it developed distinct criteria to identify potential sites for the proposed facility and to evaluate the identified sites (Exh. CPC-1, at 7.1-2). In its initial site selection process, the Company indicated that it identified potential sites based on a threshold criterion that such sites be contiguous to the DOMAC Terminal (id.; Exh. CPC-6, at 6).[147]

The Company indicated that after identifying potential sites, it evaluated those sites with six criteria, encompassing cost, environmental and reliability considerations (Exh. CPC-6, at 6). The Company indicated that its specific criteria were: (1) amount/suitability of land, to address a minimum land requirement of five acres;[148] (2) environmental suitability, to address aesthetic and noise impacts to neighboring communities as well as hazardous materials on site;[149] (3) proximity to thermal host, to account for costs of hot water lines, cold water return lines and fuel pipelines;[150] (4) site development needs, to address costs associated with site preparation, building foundations and hazardous soil cleanup; (5) proximity to utility interconnections to account for costs and environmental impacts associated with the connection of the facility to the electric grid, sewer, and other utilities; and (6) availability of land, to address the likelihood of obtaining the site (Exhs. CPC-1,

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147 The Company indicated that if the proposed facilities were contiguous to the DOMAC Terminal, easement rights and fees would be avoided and piping systems could be built above ground, thereby reducing costs and eliminating environmental uncertainties associated with removal and disposal of contaminated soil (Exh. CPC-3, at C-6).

148 The Company indicated that the minimum site size requirement is based on site requirements for gas turbine combined-cycle plant configurations in the range of 100 to 250 megawatt ratings (Exh. HO-S-8).

149 The Company noted that other environmental impacts, such as air quality, water supply and construction traffic would not vary due to the proximity of the sites (Exh. CPC-1, at 7.1-3).

150 The Company indicated that due to the topographic similarity of all sites, the distance from each site to the LNG vaporizers would constitute the determining factor for the comparison of cost and environmental impacts (Exh. CPC-1, at 7.1-3).

at 7.1-3, 7.1-4; HO-S-8).

The Company stated that it assigned a weighting factor ("WF") to each of the six criteria based on the limitation each criterion would represent in terms of estimated cost and regulatory compliance (Exh. CPC-1, at 7.1-3). The Company explained that the most severe limitation in constructing the proposed facility would be building on a site that was too small and that, therefore, the category of amount/suitability of land received a WF of ten (Exh. CPC-1, at 7.1-3). The Company indicated that the criteria of environmental suitability, proximity to thermal host, site development costs, interconnection costs and availability of land received WF's of nine, eight, seven, six, and five respectively (id. at 7.1-3, 7.1-4).

The Company stated that it scored each site by assigning numerical values, from one through ten, for each of the criteria, with higher values representing greater suitability or lower relative cost (id. at 7.2-1 through 7.2-8). CPC indicated that values for the categories of amount/suitability of land[151] and availability of land were assigned based on site characteristics, while values for other categories were assigned based on the site characteristics relative to other sites (id.).[152]

Upon review of the Company's initial site selection process, the CZM program office noted concerns that (1) the site evaluation did not consider the fact that all sites considered

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151 The Company indicated that a site with five acres of available land received a score of 5, while larger sites received higher scores (Exh. CPC-1, at 7.2-1 through 7.2-8).

152 The Company indicated that due to the similarity of sites, environmental impact scores were based primarily on the distance of the site from residential areas (Exh. CPC-2, at 7.2-1 through 7.2-7). However, scoring differed for sites with potential contamination and sites without contamination (id.). For sites where environmental contamination was not an issue, the Company indicated that it scored the environmental impact category based on a maximum of five points each for aesthetics and noise (id.). For sites with potential contamination, the value of each subcategory was not specified (id.).

by the Company were located within the Mystic River Designated Port Area ("DPA")[153] and (2) the range of potential site locations was not as broad as it could have been (Exh. CPC-3, at C-1). Thus, the CZM program office suggested that the Company: (1) evaluate potential sites in the backland portions of the IEIP, away from the Mystic and Island End Rivers; (2) consider locations within the DPA as a criterion in the evaluation of identified sites; and (3) evaluate the potential maritime uses of the primary site (id. at C-1, C-2).

In response, the Company conducted a supplemental site selection process to ensure that the primary site was still the superior site when potential conflicts related to location within the DPA were included in the siting criteria (id., app. C). The Company stated that it first identified all sites within the boundary of the IEIP and, therefore, zoned for industrial use, that met a minimum acreage requirement of five acres and were not currently maritime dependent or located directly on the waterfront (id. at C-5, C-7; Exh. HO-S-8). The Company indicated that the IEIP encompasses nearly 200 acres and that land use and topography surrounding the IEIP include: (1) the Island End and Mystic Rivers to the south and east; (2) a commercial/residential area to the northeast; (3) railroad tracks to the north; and (4) the New England Produce Center to the northwest (Exhs. CPC-3, at C-9 and figure C-2; CPC-1, figure 9.3-10). The Company then evaluated sites according to the following criteria: (1) site hazardous waste remediation implications under the Massachusetts Contingency Plan; (2) site development costs/operation expenses;[154] (3) site availability; (4) proximity to residential neighborhoods; and (5) DPA detriments (Exh. CPC-3 at C-7).

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[153] The Company indicated that a policy of the CZM program considers whether a project located in a DPA would displace any existing maritime uses at the site, conflict with adjacent maritime uses or preclude future maritime development (Exh. CPC-1, at 11.1-4).

[154] The Company noted that its analysis accounted for the disadvantages of a site that was not contiguous to the thermal host as part of the site development costs/operating expenses category, but that it was difficult to determine the precise point at which a site would become non-viable based on location not in close proximity to the thermal host (Exh. CPC-3, at C-6). The Company indicated that sites outside the IEIP were not considered due to zoning restrictions, increased distance from the steam host and greater environmental impacts (Exh. CPC-1, at 7.1-2, 7.1-3).

The Company explained that the category of DPA detriments reflected the potential conflict with DPA uses based on the site's proximity to the waterfront docks, its size and configuration, the type of existing structures on-site and transportation access (Exh. CPC-3, at C-12). The Company indicated that WFs were not developed for these criteria but that values from one through five were assigned for the respective criteria based on site advantages and disadvantages (id. at C-8, C-12 to C-28).

Further, in order to ensure that development of the primary site would not preclude future maritime use of the site, the Company evaluated other potential uses of the primary site as well as the opportunities for maritime development offered by the primary site (id. at C-29, C-42, C-43).[155] The Company concluded that: (1) the primary site did not have unique importance or value to adjacent waterfront businesses and that each such business had expansion potential on its own site; (2) sites similar to the primary site were available in the immediate vicinity; and (3) a number of underutilized waterfront sites exist throughout Boston Harbor (id. at C-43).[156]

b. Analysis

As an initial matter, the Siting Board notes that this is the first time it has been presented with a proposal to construct a cogeneration facility where the cogeneration facility developer and thermal host are wholly-owned subsidiaries of the same corporation and where the cogeneration facility was conceived specifically to serve the needs of an identified thermal host. As such, the site selection process presented in this proceeding has differed from the site selection processes addressed in other reviews of proposed cogeneration

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155 In conducting its analysis of alternative maritime uses of the primary site, the Company evaluated five potential maritime uses of the proposed site based on expansion of existing water dependent uses in the vicinity (Exh. CPC-3, at C-29).

156 The CZM program director indicated that the Company's supplemental site selection process adequately addressed concerns and was a "thorough and forthright examination of other locations for the proposed project, with an eye toward minimizing adverse effects on the suitability of this Designated Port Area (DPA) for maritime use" (Exh. CPC-6, attach. DJ-1).

facilities, where proponents have first focussed on potential steam hosts and then on potential sites in the vicinity of the chosen steam host.

Nevertheless, the Siting Board notes that the proposed project is designed primarily for electric power generation and, as such, is a much larger facility than would be necessary to serve the thermal needs of the host via cogeneration. We note that, specific business objectives associated with the development of a cogeneration facility, even where the thermal host and developer are subsidiaries of the same corporation, generally would not be sufficient reason to preclude a developer from identifying and evaluating a range of potential steam hosts. Further, there is no technical reason which would prevent this developer from proposing a cogeneration project to serve a non-affiliated steam host. However, the Siting Board also recognizes that the thermal requirements and fuel supply characteristics of DOMAC offer unique advantages relative to a typical steam host. Most significantly, DOMAC's ability to utilize hot water rather than steam provides the opportunity for increased efficiency in power production -- the power output of the cogeneration facility would not be reduced to generate steam. In addition, DOMAC would supply fuel directly to the cogeneration facility. Thus, in identifying the significant and unique advantages of DOMAC as a thermal host, the Company has provided sufficient explanation of the considerations associated with the decision to pursue development of a cogeneration facility specifically designed to serve the needs of DOMAC.

The Siting Board has recognized that once a steam host has been selected the siting of cogeneration facilities is affected by such criteria as distance from steam host, access to utility lines, fuel supply and water sources, size, zoning, and availability of sites, development costs and environmental impacts. Altresco Lynn Decision, EFSB 91-102, at 162; EEC Decision, 22 DOMSC at 127; MASSPOWER Decision, 20 DOMSC at 378-379. In this proceeding, CPC considered such criteria in its site identification and evaluation process. By limiting the potential sites first to the immediate vicinity of the thermal host and then to the entire industrial park where the thermal host is located, the Company's analysis was limited to sites zoned for industrial use as well as sites with access to fuel supply. Further, the record demonstrates that it was reasonable for the Company to limit the site selection process to the industrial park. The industrial park encompasses a large area with a number of potential sites. In addition, location beyond the boundaries of the industrial park generally would require river or railroad crossings or location within residential/commercial areas. Thus, there is limited opportunity to site the facility outside the industrial park in an economic and environmentally sound fashion.

The Company's site evaluation criteria then addressed site size, site development costs, utility interconnections, site availability and environmental impacts. The Company also included consideration of appropriate environmental impacts by addressing impacts unique to the area that would likely differ among sites in close proximity to each other, such as hazardous waste, noise and coastal zone impacts. Thus, CPC has developed site selection criteria which are generally consistent with the site selection criteria found to be appropriate in previous cogeneration facility reviews. Altresco Lynn Decision, EFSB 91-102, at 162; EEC Decision, 22 DOMSC at 321; MASSPOWER Decision, 20 DOMSC at 378-379.

With respect to weighting site selection criteria, the Siting Board has stated that the development of numerical values or weights and the ranking of alternatives based on such numerical values or weights is a reasonable step in any approach to identifying and evaluating routes or sites. In requiring the assignment of weights or values, the Siting Board does not suggest that such weights and values can or should operate as a substitute for judgment. Altresco Lynn Decision, EFSB 91-102, at 163; Berkshire Gas Company, 23 DOMSC 294, 329 (1991). Instead the Siting Board recognizes that judgment inherently requires the assignment of some weights 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.

Here, in its initial site selection process, the Company developed WFs for each of the evaluation criteria, based on the degree to which the criteria would impact construction of the proposed facility, in terms of cost and regulatory compliance, allowing for quantitative comparisons among potentially competing concerns. However, the Company did not apply weights to its supplemental site selection criteria which differed from the initial criteria primarily by addressing DPA issues. Therefore, it is unclear how location within the DPA was considered relative to other siting criteria and incorporated into the overall site evaluation process.

With respect to the scoring of sites, in both the initial and supplemental site selection analyses, the Company computed values for each criteria based on site characteristics alone or relative to other sites.[157] The initial site selection process allowed the Company to quantitatively compare sites. The supplemental site selection which confirmed the findings of the initial analysis, utilized numerical values as the basis of a qualitative comparison of the sites and also expanded the initial site selection process to thoroughly consider potential conflicts with the policies of the CZM program.

Based on the foregoing, the Siting Board finds that CPC has developed a reasonable set of criteria for identifying and evaluating alternative sites.

3. Application of Siting Criteria

a. Description

In its initial analysis, the Company identified six potential sites for the proposed facility in the immediate vicinity of the DOMAC terminal as follows: (1) the primary site, a 5.2-acre site currently occupied by an unused warehouse; (2) the Exxon site, a nine-acre site consisting primarily of abandoned, partially underground, concrete storage tanks for heavy oil; (3) the Feffer/Levin site, a 3.7-acre site currently used as a warehouse; (4) the Daniels printing site, a 4.7-acre site currently used as a warehouse; (5) the Boston Sand and Gravel site, a 6.3-acre site currently used for stockpiling and shipping bulk construction materials; and (6) the Boston Gas site, a ten-acre site currently used as an equipment storage area (Exh. CPC-1, at 7.2-1 to 7.2-7). The Company indicated that there was no public participation in the site selection process other than contact with neighboring businesses regarding site availabilities (Exh. HO-S-10).

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157 The Siting Board notes, however, that there was one discrepancy between the two scoring systems. Since a minimum area of five acres was a threshold criterion in the supplemental site selection process, no advantage was given to sites larger than five acres whereas the larger sites received higher scores in the initial evaluation.

The Company computed two overall scores for each site, one based on summing scores for all criteria without application of any WF and one based on applying WFs to the scores for respective criteria which were summed to provide an overall weighted score (id. at 7.2-8). Although the primary site did not receive the highest scores in all categories, the primary site received the highest overall weighted and unweighted scores due primarily to its availability, environmental suitability, low interconnection costs and absence of overriding detriments in other areas (id.). In summarizing the advantages and disadvantages of the other sites, CPC indicated that: (1) the Exxon, Boston Gas and Boston Sand and Gravel sites were preferable to the primary site with respect to size but were not available; (2) the Feffer/Levin site was closest to the LNG vaporizers and available, but was not large enough and was contaminated by hazardous materials in the underlying soils; and (3) the Daniels Printing site was close to the LNG vaporizers but would have high development costs (id. at 7.2-1 through 7.2-7).

Using the identification criteria developed in conjunction with the CZM program, the Company reevaluated three sites from its initial site analysis: (1) the primary site; (2) the Exxon site; (3) the Boston Gas site; and evaluated two additional sites, (1) the J.A. Foodservice site, a ten-acre site consisting of a large refrigerated warehouse and approximately five acres of open land, and (2) the combined Feffer/Levin-Daniels site (id., sec. 7; Exh. CPC-3, at C-7, C-21).[158,159]

In evaluating the sites based on the supplemental analysis, the Company indicated that each site received a score of one through five for each criteria, with a score of five representing the most favorable in terms of siting advantages (Exh. CPC-3, at C-8, C-12).

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158 The Feffer/Levin-Daniels sites were evaluated separately in the initial site selection process (Exh. CPC-1, at 7.2-2, 7.2-3). Because these sites are contiguous and neither is of adequate size, they were reevaluated as one site in the supplemental site selection process (id., figure 7.2-1; Exh. CPC-3, at C-16).

159 The Company also reviewed potential sites in the backland portions of the IEIP that did not meet minimum size requirements (Exh. CPC-3, at C-9, C-10). The Company did not consider sites that currently support maritime activities such as the Boston Sand and Gravel site (id.; Exh. CPC-2, at 7.2-5).

The Company indicated that the primary site was superior to, or equal to, each of the other sites in each category (id. at C-26, C-28). Although a numerical comparison was made for each siting issue, the Company indicated that a comparative, qualitative assessment was then made on siting advantages/disadvantages to establish the preferred site (id. at C-12). With respect to DPA detriments, the Company indicated that all sites, with the exception of the Exxon site, received a score of three because each has obstructed access to the waterfront (id.. at C-12 to C-27). The Company noted that the Exxon site scored lower that the other sites with respect to DPA detriments because it has an in-place facility, i.e., a pipeline system connecting it to waterfront docks, that could support maritime commerce (id. at C-16, C-27, C-28).

b. Analysis

In this section, the Siting Board examines whether the Company applied its siting criteria to its siting options in a consistent and appropriate manner which ensured that no clearly superior sites were overlooked or eliminated.

The record demonstrates that initially CPC applied its criteria to identify six potential sites and then quantitatively evaluate those sites. Based on its evaluation, the Company determined that the primary site is superior to the other sites based, primarily, on its location with respect to the steam host and utilities, its size and availability.

The record further demonstrates that the Company supplemented its site selection process in response to concerns raised by the CZM program office and evaluated five sites including two sites that were not initially identified. Based on a quantitative and qualitative evaluation of the sites, the Company again determined that the primary site was superior to other sites even when potential DPA detriments were taken into account.

The Siting Board notes that the Company would have more comprehensively and consistently presented the relative advantages and disadvantages of all sites if the category of DPA detriments had been added to the original set of evaluation criteria and all sites identified during the initial and supplemental site selection processes had been evaluated by such criteria. However, the Siting Board also notes that no site scored better than the primary site with respect to DPA detriments and that all of the sites larger than 5 acres had disadvantages relative to the primary site in a number of categories. Therefore, it is unlikely that results would have been different with inclusion of DPA detriments in an evaluation of all sites.

In addition, the Siting Board notes that the identification of sites could have benefited from input from the surrounding communities and public participation in the process. In the past, project proponents have been encouraged to include community input into their site selection process. Altresco Lynn Decision, EFSB 91-102, at 166; 1993 BECo Decision, EFSB 90-12/90-12A at 52; 1990 Berkshire Decision, 20 DOMSC at 163. The Siting Board strongly reiterates its recommendation that in the future CPC and other petitioners should include the local community and governmental representatives in an open, participatory process from the inception of the project.

Nevertheless, based on the foregoing, the Siting Board finds that CPC 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.

4. Geographic Diversity

CPC asserted that, consistent with Siting Board precedent, in selecting the proposed site it was not required to provide a noticed alternative site with some measure of geographic diversity (Company Brief at 103-104). CPC argued that the Siting Council determined that the identification of a noticed alternative site is not required for proposals to construct cogeneration facilities if the cogeneration proponent (1) has a steam sales agreement with an existing steam purchaser sufficient to qualify it for QF status, and (2) has a proposed site fully within the property boundaries of the principal steam host (id. at 103, citing, EEC Decision, 22 DOMSC at 315; West Lynn Decision, 22 DOMSC at 78).

CPC asserted that the proposed project meets the aforementioned standard of review even though the proposed project (1) would provide hot water, rather than steam, to DOMAC, and (2) would not be located within the DOMAC property boundaries (id. at 103-104). With regard to steam sales, the Company stated that DOMAC prefers to receive thermal energy in the form of hot water rather than steam and that it has executed a thermal energy sales agreement with DOMAC which provides for the sale of a sufficient amount of hot water for the proposed project to qualify for QF status (id.; Exhs. HO-B-9; HO-B-9, att.; HO-B-6; HO-B-6, att.). The Company maintained that the sale of hot water, rather than steam, meets the standard given that the proposed facility qualified for QF status (Company Brief at 104). With regard to location of the proposed facility, the Company indicated that the proposed facility cannot be placed within the property boundary of the DOMAC Terminal due to the layout of the DOMAC Terminal and presence of containment dikes (Exh. HO-S-5). However, the Company indicated that the proposed site directly abuts the property boundary of the DOMAC Terminal (Exhs. CPC-1, at 3.1-4; HO-S-5). In addition, the Company indicated that the owner of the proposed site, MassGas, Inc., is an affiliate of DOMAC and that both MassGas, Inc. and DOMAC are part of the Cabot Corporation organization (id. at 1.1-1; Exhs. HO-B-2; HO-PV-14, att. 1). Therefore, the Company asserted that, given the adjacent location of the proposed site to DOMAC and the Cabot Corporation structure, the proposed site is effectively and fully within the boundaries of the principal thermal energy host.

With respect to steam sales, the Siting Board notes that, although the proposed facility would provide thermal energy in the form of hot water rather than steam, it qualified for QF status as a cogeneration facility. The Siting Board agrees that, for purposes of the first part of the Siting Board standard, the proponent has effectively established that it has a thermal energy sales agreement with an existing user sufficient to qualify it for QF status. In addition, the record shows that: (1) the layout of the thermal host facilities does not allow for construction of the proposed facility within the property boundary of the thermal host; (2) the proposed site is located directly adjacent to the thermal host property boundary; and (3) the proposed site owner and thermal host are part of the same corporate entity. Therefore, for the purposes of this review, the Siting Board considers the proposed site to be fully within the property boundaries of the principal thermal host. Accordingly, based on the foregoing, the Siting Board finds that CPC is not required to provide a noticed alternative site with some measure of geographic diversity.

The Siting Board also considers geographic diversity in light of the location of the proposed site within the CZM area as defined pursuant to 980 C.M.R. 9.00 (Exh. CPC-1, at 7.3-1, 7.3-2). The Company noted that CZM Policy 8 refers to consideration of an alternative site outside the coastal zone as part of evaluating proposed energy facilities which are not considered coastally dependent (id. at 7.1-6). The Company indicated that the CZM program stated that it would be appropriate for the Siting Board to allow for exceptions to the requirement of considering an alternative inland site, provided that it is clearly demonstrated that no reasonable opportunity exists to locate the proposed cogeneration facility outside the coastal zone (Exh. CPC-3, at B-4, B-5). The Company stated that it had addressed the applicability of CZM Policy 8 in its supplemental site selection process, developed in conjunction with and approved by the CZM program office (Exh. HO-S-6).[160]

Specifically, as noted above in Section III.B.2., the Company conducted a supplemental site selection process in response to CZM program concerns in which it identified additional sites[161] and included consideration of potential maritime uses of each site in its evaluation of the sites (Exh. CPC-3, app. C). In addition, CPC considered whether construction of the proposed facility on the proposed site would pre-empt future development of the proposed site for maritime commerce (id.). Thus, CPC acted in accordance with the intent of CZM Policy 8 in conducting a supplemental site selection process that addressed CZM concerns regarding use of the proposed site for an energy facility. In addition, the project is a cogeneration project, specifically tied to the location of its thermal host, consistent with the standard set forth in the MASSPOWER Decision, supra.

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160 In comments of the CZM to the Final Environmental Impact Report, the CZM's director commended the Company for providing thorough examination of other locations for the proposed project which considered whether significant opportunity would be lost to accommodate future water-dependent industries on the proposed site (Exh. HO-S-6, att.)

161 In its supplemental site selection process, the Company attempted to identify potential sites in the backland portion of the IEIP, still within the coastal zone, but concluded none of these sites were viable alternatives (Exhs. CPC-3 at C-9, C-10, C-11; CPC-1, at figure 9.1-10).

Therefore, the Siting Board also finds that CPC has complied with the CZM requirement that its site evaluation and comparison "include a justification of the necessity for or advantage of coastal siting" for its proposed facility. 980 C.M.R. 9.02(1)(a).

5. Conclusions on the Site Selection Process

The Siting Board has found that: (1) CPC has developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) CPC has appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures that it has not overlooked or eliminated any clearly superior sites; and (3) CPC is not required to provide an alternative site with some measure of geographic diversity.

Further, the Siting Board has found that CPC has complied with the CZM requirement that its site evaluation and comparison "include a justification of the necessity for or advantage of coastal siting" for its proposed facility.

Accordingly, the Siting Board finds that CPC has considered a reasonable range of practical facility siting alternatives.

C. Environmental Impacts, Cost and Reliability of the Proposed Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to 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. 1993 BECo Decision, EFSB 90-12/90-12A at 29-30; 1991 Berkshire Decision, 23 DOMSC at 324. In cases where a noticed alternative is not required, the facility proponent still must demonstrate that the proposed site for the facility will minimize environmental impacts and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Altresco Lynn Decision, EFSB 91-102, at 169; EEC Decision, 22 DOMSC at 316-316.

An overall assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Altresco Lynn Decision, EFSB 91-102, at 170; 1993 BECo Decision, EFSB 90-12/90-12A at 30; EEC Decision, 22 DOMSC at 334, 336. A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Altresco Lynn Decision, EFSB 91-102, at 170; 1993 BECo Decision, EFSB 90-12/90-12A at 31; EEC Decision, 22 DOMSC at 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Altresco Lynn Decision, EFSB 91-102, at 170; 1993 BECo Decision, EFSB 90-12/90-12A at 31; EEC Decision, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in respective facility proposals. Altresco Lynn Decision, EFSB 91-102, at 170; 1993 BECo Decision, EFSB 90-12/90-12A at 31; EEC Decision, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular decision must be clearly described and consistently reviewed from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[162] Altresco Lynn Decision, EFSB 91-102, at 170; 1993 BECo Decision, EFSB 90-12/90-12A at 31-32. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Altresco Lynn Decision, EFSB 91-102, at 171; 1993 BECo Decision, EFSB 90-12/90-12A at 32.

Accordingly, in the sections below, the Siting Board examines the environmental and cost impacts of the proposed facilities at the Company's proposed site to determine (1) whether environmental impacts would be minimized at the site, and (2) whether an

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[162] The Siting Board notes that project proponents are required to submit to the Siting Board a substantially accurate and complete description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of a generating facility provide a description of the primary and alternative sites and the surrounding areas in terms of: natural features, including, among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impact of the facility in terms of its effect on the natural features described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 C.M.R. 7.04(8)(e).

In cases where a site is proposed in the coastal zone, as defined by CZM statutes and regulations, the Siting Board's Coastal Zone Facility Site Selection, Evaluation and Assessment Regulations require: (1) an environmental description of each site and its vicinity, including a review of: significant land, air, and water use; ecology; geology; hydrology; meteorology; (2) an environmental analysis of construction impacts; (3) an environmental analysis of facility operation, including, but not limited to, land, air and water use impact, waste impacts, visual and aesthetic impacts; (4) a socioeconomic impact analysis, including measures to mitigate adverse impact during construction and operation; and (5) an analysis of all measures taken to comply with land, air, and water use and ecological standards, policies, regulations, bylaws and statutes of the Commonwealth and its political subdivisions. 980 C.M.R. 9.02(1)(b).
Finally, the Siting Board notes that G. L. c. 164, § 69J also requires that plans for construction of new facilities be consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth.

appropriate balance would be achieved at the site among conflicting environmental concerns as well as among environmental impacts, cost and reliability.

2. Environmental Impacts of the Proposed Facility

a. Air Quality

The Company asserted that the stack emissions from the proposed facility have been adequately minimized and will have acceptable impacts on air quality (Company Brief at 113). In the following sections, the Siting Board reviews applicable air quality regulations, the identification and control of facility emissions and the impact of facility emissions on ambient air quality.

i. Applicable Regulations

CPC indicated that review of federal and state air quality requirements applicable to the operation of the proposed facility would be included within the MDEP review of its comprehensive air plans application (Exh. CPC-4, sec. 3; Company Brief at 118). The Company indicated that the principal criteria for approval of its air plans application include a demonstration that: (1) the Best Available Control Technology ("BACT") would be utilized;[163] (2) the impact of facility emissions would not result in excedances of NAAQS; and (3) the quantity and impact of facility emissions would comply with all applicable state regulations and policies (Exh. CPC-2, at 3.3-1, 3.3-2, 3.3-6, 3.3-7).[164]

With respect to NAAQS, the Company indicated that ambient air quality standards

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163 The Company indicated that BACT is an emission limitation based on the maximum degree of reduction of any regulated air pollutant which MDEP determines, on a case-by-case basis, is achievable for such a facility, taking into account energy, environmental and economic impacts (Exh. CPC-2, at 3.3-7).

164 The Company indicated that the MDEP issued a Conditional Approval of its Major Comprehensive Air Plans Approval Application on July 31, 1992, including pre-construction and compliance testing provisions (Exh. HO-E-1). The Siting Board notes that G.L. c. 164, § 69J states Siting Board approval must be received before any state or local agency issues a final construction permit for proposed facilities.

have been established for the following six criteria pollutants: (1) SO_2; (2) PM-10; (3) NOx; (4) CO; (5) ozone;[165] and (6) lead (Exh. CPC-4, at 3-2). The Company further indicated that geographical regions are classified as attainment, non-attainment or unclassified on a pollutant-by-pollutant basis depending on whether NAAQS are being met, and that air quality regulations are more stringent in nonattainment areas where criteria pollutants are emitted above certain threshold levels (Exhs. CPC-2, at 3.3-2; CPC-8, at 5). The Company noted that the Everett area is classified as an attainment area for NOx and SO_2, a non-attainment area for CO and ozone[166] and is unclassified for PM-10 (Exhs. CPC-8, at 5, 7; HO-E-34).[167,168]

With respect to state regulations and policies, the Company stated that the Massachusetts Acid Rain Regulations would limit the emission rate of SO_2 at the proposed facility and that Massachusetts regulations specific to the Metropolitan Boston Air Pollution Control District, of which Everett is a part, would limit fuel sulfur content (Exh. CPC-2, at 3.3-7).[169]

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165 The Company indicated that ozone is not emitted from combustion sources and is, therefore, not regulated (Exh. CPC-8, at 5). The Company noted that instead, VOCs, which together with NOx are precursors to ozone formation in the atmosphere, are regulated (id.; Exh. CPC-2, at 3.3-4).

166 The Company noted that the entire state of Massachusetts is classified as non-attainment for ozone (Exh. CPC-8, at 8).

167 The Company noted that emissions of VOC and CO would be less than the applicable 100 tpy threshold level that triggers a non-attainment review, and, as such, a non-attainment review is not required (Exh. CPC-2, at 3.3-3).

168 The Company noted that the federal Prevention of Significant Deterioration ("PSD") program establishes additional air quality related criteria for attainment areas and applies to major new sources of air pollutants (Exh. CPC-4, at 3-4, 3-5). The Company further noted that because emissions of each criteria pollutant would be less than 250 tpy, the proposed facility would not be classified as a major new source and thus, would not be subject to PSD regulations (id.).

169 The Company noted that a MDEP policy limiting one-hour ambient NOx

(continued...)

In addition to the air plans approval, the Company indicated that the proposed project would be subject to federal regulations including New Source Performance Standards ("NSPS") and the acid rain provisions of the 1990 Clean Air Act ("CAA") Amendments (id. at 3.3-6). The Company stated that NSPS apply to new or modified major sources of air pollutants and limit NOx emissions and fuel sulfur content (id.). The Company further stated that the acid rain provisions of the 1990 CAA Amendments would require the Company to obtain allowances for each ton of SO_2 emitted from the proposed facility, beginning in the year 2000 (id.).[170]

ii. Identification and Control of Emissions

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants,[171] and CO_2 (Exhs. CPC-4, Table 4.1-1; HO-E-19). However, the Company asserted that the emissions from the proposed facility have been minimized to the greatest extent possible due to the combination of efficient

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[169](...continued) concentrations would not apply to this proposed facility, as NOx emissions would be less than the threshold amount of 250 tpy (Exh. CPC-2, at 3.3-8). In addition, the Company indicated that the MDEP policy pertaining to allowable impacts of emissions of air toxics would not apply in that the proposed project would not emit significant quantities of air toxics (id.).

[170] The Company stated that it expects to purchase SO_2 emission allowances in accordance with applicable United States Environmental Protection Agency ("EPA") regulations (Exh. HO-E-17). The Company stated that provisions of the 1990 CAA Amendments relating to sources that emit more than 50 tpy of VOC or NOx likely would not apply to the proposed facility because the Company anticipates that it will receive a permit prior to the effective date of the provisions (Exh. CPC-2, at 3.3-3 through 3.3-5).

[171] As noted above, criteria pollutants are those air emissions for which NAAQs have been set -- those six pollutants listed in Section III.C.2.a.i., above. Non-criteria pollutants, regulated under the federal PSD program, that would be emitted from the proposed facility, include beryllium, fluoride, mercury and sulfuric acid mist (Exh. CPC-4, at 4-13, 4-14).

technology,[172] clean fuels and add-on controls (Exh. CPC-2, at 7.3-1, 7.3-2).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility based on information obtained from equipment manufacturers and literature review (id.; Exhs. CPC-8, at 3; HO-E-29). The Company stated that estimated emissions were based on operation of the proposed facility at full load for every hour of the year with maximum (30 days) oil-firing (Exh. CPC-8, at 3). The Company stated that such operating conditions were unlikely to occur and that, therefore, estimated emissions would exceed actual facility emissions (id.).[173]

(A) Criteria Pollutants

The Company asserted that the assumed facility emission rate for each criteria pollutant was representative of BACT (Exh. CPC-2, at 7.3-2).

With regard to NOx emissions, the Company indicated that NOx formation results from the reaction of nitrogen, in both the fuel and combustion air, with oxygen (id. at 7.3-2, 7.3-3). The Company noted that fuel oil contains more nitrogen than natural gas and that NOx emissions would be limited to six ppm during natural gas firing and 17 ppm during oil firing, or 198.8 tpy (id. at 7.3-3).[174] The Company explained that NOx emissions would

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172 The Company explained that its advanced technology combustion turbine will operate at higher temperatures than conventional combustion turbines, resulting in greater fuel efficiency (Exh. CPC-2, at 7.3-1). The Company stated that, since air pollutant emissions are a direct result of fuel utilization, the amount of emissions per unit of electricity generated would be lower than for conventional combustion turbines (id.).

173 In addition, in estimating facility emissions, CPC assumed lower than average ambient temperatures and consistent use of the air chiller for ambient temperature above 45 degrees to account for increased power output and increased emissions with cooler temperatures (Exh. CPC-4, at 2-9).

174 The Company noted that the reduction of NOx to 6 ppm for natural gas firing is below the Northeast States for Coordinated Air Use Management ("NESCAUM") recommendation of 9 ppm for stationary gas turbines (Exh. CPC-2, at 7.3-3).

be controlled by use of advanced, dry low-NOx combustor technology[175] in combination with a SCR system (id.). The Company explained that SCR is a post-combustion process whereby ammonia, injected into the turbine exhaust stream in the presence of a metal catalyst, reacts with NOx to form nitrogen and water vapor (id.).[176]

The Company stated that SO_2 emissions, which result from the oxidation of sulfur compounds present in fuel, would be limited by the use of natural gas, which contains minimal sulfur, as the primary fuel, and the use of low-sulfur light distillate oil, which contains 0.05 percent sulfur, as backup fuel (id. at 7.3-4).[177] The Company indicated that maximum SO_2 emissions would be 0.0006 lbs/MMBtu for natural gas firing and 0.054 lb/MMBtu for oil firing, or 38.3 tpy (Exh. CPC-3, at Table 7.3-1).

The Company indicated that emissions of CO and VOCs, which are by-products of incomplete combustion, would be limited by the high efficiency of combustion in the turbine (Exh. CPC-2, at 7.3-4, 7.3-5). CPC indicated that CO emissions would be limited to 100 tpy[178] and that VOC emissions would be limited to 15.9 tpy (Exh. CPC-3, Table 7.3-1).

The Company stated that PM-10 emissions, which include by-products of incomplete

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175 The Company indicated that water would be injected into the combustion turbine during oil firing to control NOx emissions (Exh. CPC-2, at 7.3-3).

176 The Company stated that although some types of catalysts contain hazardous materials, such materials would not be emitted into the atmosphere and spent catalysts would be recycled or disposed by the catalyst suppliers as part of the catalyst replacement supply agreement (Exh. HO-E-40).

177 The Company noted that LNG is essentially free of sulfur and that pipeline gas contains trace amounts of sulfur because sulfur-bearing compounds are added to pipeline gas for odor detection purposes (Exhs. HO-E-32; CPC-2, at 7.3-4).

178 CPC indicated that if actual emission rates determined during initial compliance testing demonstrated that CO emissions would be above 100 tpy, the Company would take measures to reduce emissions below 100 tpy, including turbine adjustments or modifications, operating limits or installation of a CO oxidation catalyst (Exh. CPC-3, at 7-2, 7-3). The Company explained that a CO oxidation catalyst would reduce CO emissions by oxidation of CO to CO_2 and would also have the potential to increase PM-10 emissions and decrease VOC emissions (Exh. HO-E-77). CPC estimated that use of an oxidation catalyst would result in an additional 138 tpy of CO_2 (id.).

combustion as well as trace ash constituents of oil, would be minimized by the use of natural gas and the high efficiency of combustion in the turbine (Exh. CPC-2, at 7.3-5). CPC indicated that PM-10 emissions would be limited to 46.3 tpy (Exh. CPC-3, Table 7.3-1).

Finally, the Company stated that emissions of lead would be minimized by the use of natural gas which is essentially lead free and distillate oil which contains only trace amounts (Exh. CPC-4, at 4-13).

(B) Other Pollutants

The Company indicated that, in addition to criteria pollutants, ammonia, beryllium, fluoride, mercury, sulfuric acid mist and CO_2 would be emitted by the proposed facility (Exh. CPC-2, at 7.3-4 to 7.3-6). With regard to ammonia emissions, the Company stated that, in order to achieve high NOx-reduction efficiency, excess ammonia would be injected into the exhaust stream and that ammonia slip would occur when unreacted ammonia was emitted to the atmosphere (id. at 7.3-4). However, the Company stated that ammonia slip would be limited through close control of the ammonia mixing and injection rate (id.).[179]

The Company indicated that emissions of beryllium, fluoride, and mercury would be minimized by use of natural gas which is essentially free of these elements and use of light distillate oil which contains only trace amounts (id. at 7.3-5). In addition, the Company indicated that sulfuric acid mist emissions, which result from the combination of sulfur compounds in the exhaust gas with water vapor, also would be minimized by the use of natural gas (id. at 7.3-6).

Finally, the Company indicated that approximately 943,000 tpy of CO_2 would be emitted from the proposed facility (Exh. HO-E-83).[180] The Company noted that CO_2 is a product of fossil fuel combustion and that emissions would be minimized by the high

179 The Company noted that ammonia slip concentrations would be limited to a maximum of 10 ppm, in accordance with NESCAUM guidelines (Exh. CPC-2, at 7.3-4).

180 The Company estimated CO_2 emissions to be 908,000 tpy based on natural gas firing at full load for the entire year (Exh. HO-E-83). The Company further estimated that CO_2 emissions would increase by 35,000 tpy with oil firing for 30 days (id.).

efficiency design of the proposed facility which uses less fuel per unit output and by the use of natural gas, which produces less CO_2 per MMBtu than oil or coal (Exh. HO-E-19).

The Company asserted that the CO_2 emissions from the proposed facility would be adequately minimized (Company Brief at 136). In support, the Company stated that operation of the proposed facility would displace more CO_2 emissions than it would generate but that, as an additional measure to offset CO_2 emissions, it would contribute $5,000 per year for 20 years to the Massachusetts ReLeaf Program ("MASS ReLeaf") for tree planting (Exhs. CPC-9, at 37-41; HO-E-76).[181] The Company noted that its contribution to MASS ReLeaf would provide for the planting of 33 "good-sized" trees per year and would offset approximately 0.1 percent of facility emissions (Tr. 3, at 52-53).[182]

The Company also asserted that its proposed CO_2 mitigation approach complies with the standards for evaluation of CO_2 emissions and mitigation set forth by the Siting Council in the Eastern Energy Corporation, 25 DOMSC 296 (1992) ("EEC Compliance Decision") (Company Brief at 131-135). With regard to the evaluation of CO_2 emissions, the Company stated that the Siting Council found in the EEC Compliance Decision that this type of dispatch and backout analysis would be an integral component of an acceptable CO_2 mitigation strategy (id. at 131-132). With regard to the amount of proposed mitigation, the Company stated that the evidence regarding the dispatch analysis clearly demonstrates that the CO_2 emissions from the proposed facility would be adequately minimized in accordance

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181 The Company estimated that CO_2 emissions from the proposed facility would be approximately 943,000 tpy and that the displacement of existing NEPOOL units would offset 500,000 more tpy of CO_2 than would be produced by the proposed facility (Exhs. HO-E-76; CPC-9, at exh. RLC(38)). In addition, the Company noted that operation of the proposed facility would result in a decrease in CO_2 emissions from DOMAC LNG vaporization -- a decrease equivalent to approximately five percent of the emissions of the proposed facility (Exhs. HO-E-19; HO-E-75).

182 CPC based its estimate of CO_2 emissions offsets on (1) a cost of $150 per tree, and (2) CO_2 absorption capability of 30 tons per tree over the life of the tree (Tr. 3, at 53). In the Altresco Lynn Decision, EFSB 91-102, at n.202, the Siting Board noted that an assumed offset of 30 tons of CO_2 over the life of a planted tree -- 40 years -- would be equivalent to an offset of 0.75 tpy per tree.

with the EEC Compliance Decision, where the Siting Council found that the appropriate level of CO_2 offsets would be related to a proposed facility's total or incremental CO_2 emissions (id. at 133). The Company added that its proposed contribution to MASS ReLeaf is an additional measure to offset CO_2 emissions which significantly exceeds previous Siting Council CO_2 emissions offset precedent for gas-fired facilities (id. at 134).[183] The Company further noted that the Siting Council has found that local tree planting is an acceptable means of CO_2 mitigation and that, therefore, its tree planting proposal would be an acceptable CO_2 mitigation strategy (id. at 135). Finally, the Company stated that additional costs for CO_2 mitigation should not be required by the Siting Board for the proposed facility in that additional costs would eliminate the appropriate balance between cost and environmental impact for this facility (id.).

iii. Predicted Impacts

The Company asserted that the air quality impacts of the proposed facility would be well below applicable standards and would be acceptable (Company Brief at 136).

In order to assess compliance with the NAAQS, CPC performed a dispersion modeling analysis to predict ambient concentrations of criteria pollutants which would result from the operation of the proposed facility, using two EPA air quality models, the Industrial Source Complex Short-Term ("ISCST") model and the Valley model[184] (Exhs. CPC-4, sec. 5; CPC-8, at 6-7). The Company indicated that where initial modeling predicted facility contributions to ambient concentrations in excess of EPA Significant Impact Levels

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183 CPC noted that at the time of the CPC proceeding, the only CO_2 mitigation measure that had been accepted by the Siting Council was Enron's proposed one-time contribution to MASS ReLeaf of $5,000 (Company Brief at 134).

184 The Company indicated that the Valley model is used for receptor terrain elevations above stack top while the ISCST model accounts for multiple sources, terrain elevations below the stack top and downwash effects of nearby structures (Exh. CPC-4, at 5-11).

("SIL"),[185] interactive modeling would be required to demonstrate that the predicted ambient concentrations from the proposed facility, when added to background concentrations and ambient concentrations due to other major sources, would be below appropriate NAAQS (Exh. CPC-4, sec. 5). The Company stated that initial modeling indicated that only three-hour and 24-hour SO_2 contributions from the proposed facility were above SILs but that refined interactive modeling demonstrated that the ambient concentration with the proposed facility would be below the NAAQs (id. at Table 5.6-1; Exh. CPC-8, at 7).[186]

In predicting ambient concentrations, the Company assumed a stack height of 240 feet (Exh. CPC-3, at 7-6). In determining the appropriate stack height for the proposed facility, CPC indicated that it considered: (1) the potential aerodynamic downwash effects of the adjacent DOMAC LNG tanks and cement silos; (2) the EPA good engineering practice ("GEP") formula for determining stack height;[187] and (3) a City of Everett zoning ordinance limiting stack height to 150 feet (Exh. CPC-4, at 7-3 through 7-6). The Company stated that based on a wind tunnel study to evaluate the effect of the adjacent structures on ambient air quality with a 150-foot stack and other stack heights, it concluded that a stack height of less than 240 feet would not be acceptable (Exh. HO-E-14).[188,189]

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185 CPC indicated that SILs are a small fraction of the comparable NAAQS and that if initial modeling predicted facility contributions to ambient concentrations below SILs, compliance with NAAQS would be demonstrated and no further modeling would be required (Exh. CPC-8, at 7).

186 In addition, the Company performed a screening-level analysis to evaluate the shoreline wind flows on ground level concentrations of criteria pollutants (Exh. HO-E-39). The Company's analysis predicted impacts below ISCST-predicted impacts (id.).

187 The Company indicated that GEP stack height is the lowest height of a stack that would not be subject to downwash from other structures and is defined as the sum of the height plus one and one half times the lesser of the height or width of the tallest adjacent structure (Exh. CPC-2, at 7.3-7, 7.3-8). The Company calculated the GEP stack height to be 472.5 feet (id. at 7.3-8).

188 The Company indicated that the proposed facility would be located between two large LNG tanks to the northwest and a cluster of cement silos to the southeast (Exh. CPC-
(continued...)

iv. Analysis

CPC has provided adequate support for its assertion that emissions of criteria pollutants and other regulated pollutants from the proposed facility have been minimized and that emissions of criteria pollutants would have acceptable impacts on existing air quality. The Siting Board notes that NOx emissions for gas-firing would be controlled to the same level as NOx emissions from the recently approved Altresco facility in Lynn, Massachusetts, the lowest emission rate reviewed by the Board to date. See, Altresco Lynn Decision, EFSB 91-102, at 174.

With respect to an analysis of CO_2 impacts, the Siting Council first established in the Enron Decision the requirement that all applicants of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 impacts. 23 DOMSC at 196. In the EEC Compliance Decision, the Siting Council further provided that future applicants must present alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, to demonstrate that all cost-effective approaches have been adequately considered. 25 DOMSC at 358-360. The Siting Council also stated that it would be preferable for applicants to address the adequacy of CO_2 mitigation in terms of the quantity of CO_2 emission offsets to be attained rather than in terms of the cost to be committed for providing CO_2 emission offsets. Id. at 362. Further, the Siting Council set forth general criteria it would consider to determine the adequacy of CO_2 mitigation in such

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[188](...continued)
3, at 7-4). In order to assess the effect of these adjacent rounded structures on ground-level concentrations, the Company performed a wind tunnel analysis for stack heights of 150 feet and higher (Exh. HO-E-14, at 1). The Company indicated that for stack heights of 150 to 240 feet, airflow around the LNG tanks and cement silos would cause the exhaust plume of the proposed facility to downwash and therefore concluded that a stack height of 240 feet was the minimum stack height that would not produce excessive ground-level concentrations (id., at 1-2; Exh. CPC-4, at 7-6). The Company added that alteration of site layout would not result in a stack height lower than 240 feet (Exh HO-E-16).

[189] The Company indicated that it has received a zoning variance from the City of Everett to construct a stack higher than 150 feet (Exh. CPC-6, attach. DJ-5).

reviews, as well as approving a particular cost commitment for that project.[190] Id. at 361-367.

In the Siting Board's most recent review of a proposed cogeneration facility, where the initial filing predated the above holdings, the Siting Board recognized that a determination of an appropriate level of CO_2 offsets should bear a reasonable relationship to the level of CO_2 offsets required of EEC in the EEC Compliance Decision. Altresco Lynn Decision, EFSB 91-102, at 210-211. Thus, the Siting Board required an increase in the proposed level of CO_2 offsets in that case such that 0.348 percent of facility emissions would be offset. Id. at 213.[191]

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190 The Siting Council stated that it may consider various relevant project factors -- for example facility cost, facility CO_2 emissions, and any increment of such emissions exceeding the emissions of displaced capacity ("net-of-displacement emissions") -- in order to determine the appropriate level of CO_2 mitigation for proposed facilities. EEC Compliance Decision, 25 DOMSC at 365. In establishing that both total emissions and net-of-displacement emissions could be appropriate indicators, the Siting Council noted that it may not be clear as to whether a proposed facility would serve primarily to displace existing power generating facilities or to meet future load growth. Id. at 363. The Siting Council recognized that, to determine the appropriate level of CO_2 mitigation, it is necessary to relate a proposed facility's CO_2 emissions to net changes in regional or national emissions. Id. To the extent that a proposed facility would displace existing power generating facilities, there may be a beneficial or adverse impact on regional or national levels of CO_2 emissions corresponding to the difference between such proposed facility's emissions and those of the displaced generation. Id. To the extent that a proposed facility is to be built in whole or in part to meet load growth, new generation may be added to the region's supply faster than old generation is retired or otherwise displaced. Id. In this latter situation, the net impact of a proposed facility on regional/national CO_2 emissions may not correspond to the difference between its emissions and those of any alternative energy resource, but rather may reflect more closely the total CO_2 emissions from such proposed facility. Id.

191 In the Altresco Lynn Decision, EFSB 91-102, at 212, the Siting Board recognized that, based on the assumption that a planted tree would provide 0.75 tpy of CO_2 offsets, the required CO_2 mitigation in the EEC Compliance Decision would offset approximately 0.8 percent of that facility's CO_2 emissions but that, on-site tree clearing would reduce offsets to 0.348 percent of facility emissions. See, EEC Compliance Decision, 25 DOMSC at 350, 354, 366-367.

The Siting Board notes CPC's initial filing in this proceeding also predated both the above holdings concerning analytical requirements for CO_2 impacts. CPC proposes to offset approximately 0.1 percent of the proposed facility's CO_2 emissions over a 20-year time period. Thus, as in the EEC Compliance Decision and the Altresco Lynn Decision, CPC's proposed CO_2 offsets are a small fraction of expected total CO_2 emissions from the proposed facility.

The Siting Board recognizes that to the extent the proposed facility would serve to displace existing generation, its expected CO_2 emissions would be exceeded by those from displaced capacity, and could be as little as 65 percent of the CO_2 emissions from displaced capacity. In addition, operation of the proposed facility would displace 48,000 tpy of CO_2 emissions from the existing DOMAC Terminal. In contrast, the required CO_2 offsets in the EEC Compliance Decision were a small fraction of that facility's net-of-displacement emissions, assuming the project would serve to displace existing generation. Id. at 366. Further, EEC's proposed offsets were partly negated by expected on-site tree clearing for that facility, while CPC's proposed facility would not require on-site tree clearing.

Nonetheless, on a MW-for-MW basis, CPC's total CO_2 emissions are approximately 38 percent of those reviewed in the EEC Compliance Decision, while its proposed CO_2 offsets are less than five percent of those required of EEC (and about eight percent of those proposed by EEC). Accordingly, the Siting Board finds that CPC has not established that the CO_2 emissions impacts of the proposed facility would be minimized.[192]

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of CPC's proposed BACT, and with the exception of CO_2 emissions, the

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[191](...continued)
clearing would reduce offsets to 0.348 percent of facility emissions. See, EEC Compliance Decision, 25 DOMSC at 350, 354, 366-367.

[192] The Siting Board notes that, on a MW-for MW basis, CPC's total CO_2 emissions are approximately 150 percent of those reviewed in the Altresco Lynn Decision, while its proposed CO_2 offsets are approximately 34 percent of those required (and about three times greater than those proposed) in the Altresco Lynn Decision.

environmental impacts of the proposed facility would be minimized with respect to air quality.[193]

b. Noise

The Company asserted that the noise impacts of the proposed facility have been adequately minimized and that the proposed facility would have an acceptable impact on community noise levels (Company Brief at 137). The Company stated that the noise impacts of the proposed facility would comply with MDEP regulations and policies that restrict (1) increases in the broadband sound level to ten decibels ("dBA") above the pre-existing ambient level, and (2) production of a pure tone sound (Exh. CPC-5, at 4, 5).[194] The Company noted that the MDEP noise policy has been applied at the nearest residences and nearest residential property lines and that the MDEP has approved higher noise increases at property lines within non-residential land uses where noise levels would not be incompatible with existing or potential use of adjacent parcels (id.).

In order to assess the noise impacts of the proposed facility, CPC first established baseline noise levels in the vicinity of the proposed facility at residential and property line receptors (Exh. CPC-2, at 5.4-1 through 5.4-11). CPC then predicted operational noise levels from facility equipment, predicted operational noise contributions at the receptors, and

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193 The Siting Board reviews, in Section III.C.3., below, whether CPC's proposed level of CO_2 mitigation or a higher level of CO_2 mitigation would allow the Company to establish that the CO_2 emissions impact of the proposed facility would be minimized consistent with minimizing cost.

194 The Company indicated that the noise level regulated by the MDEP is the L90 level which is the noise level that is exceeded 90 percent of the time (Exh. CPC-2, at 5.4-3, 5.4-4). The Company also indicated that pure tonal sounds are any octave band level which exceeds the levels in adjacent octave bands by 3 dBA or more (Exh. CPC-4, at 6.2-1).

MDEP review of noise impacts is included in its review of the Major Comprehensive Air Plans Approval Application (id. section 6). As noted in Section III.C.2.a.i, above, the MDEP has issued a Conditional Approval of said application (Exh. HO-E-1).

evaluated the impact of operational noise on ambient noise levels (Exh. CPC-4, sec. 6). In establishing baseline noise levels, CPC measured weekday daytime and nighttime and weekend daytime and nighttime ambient noise levels at the five closest residential receptors and at the northeast corner of the site property (Exh. CPC-2, at 5.4-1).[195,196] CPC indicated that the lowest background noise level for each receptor was measured during the weekend nighttime period (id. at 5.4-5).

In predicting operational noise levels associated with facility operation, the Company first identified the major potential noise sources and then estimated expected operational noise levels based on engineering data for specific equipment and other technical data (Exh. CPC-5, at 5-6; Tr. 1, at 18-21).[197] In order to predict facility impacts at each receptor, the Company applied a mathematical noise propagation loss model[198] to estimate the noise from each major source at each receptor and to add the noise levels from the

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195 The Company indicated that because the site is small, one property line measurement was sufficient to characterize background noise on each side of the site (Exh. CPC-4, at 6.3-3; Tr. 1, at 10). The Company indicated that five residential receptors were chosen based on: (1) maps of the site vicinity; (2) facility plans; and (3) site visits (Exh. CPC-5, at 5).

196 The Company indicated that noise measurements were made during a week-long period in November (Exh. CPC-2, at 5.4-2, 5.4-3). The Company indicated that outdoor conditions during measurement periods -- low winds, dry roads, moderate temperatures and minimal insects -- were representative of quiet periods (Exh. HO-E-44).

197 The Company indicated that the major exterior noise sources at the proposed facility would be the air intake and exhaust for the combustion turbine, the air-cooled condenser, the auxiliary air cooler, the HRSG and the transformers (Exh. CPC-4, at 6.3-1). The Company indicated that the interior noise sources would be the turbine generator units and ancillary equipment (id.). The Company noted that operation and resulting noise from the air cooled condenser likely would be reduced in the winter but that maximum operation conditions were assumed in facility noise modelling (Exh. HO-E-43).

198 The Company noted that the model is conservative in that it does not take into account noise attenuation caused by ground absorption or sound-velocity gradient effects (Exh. CPC-5, at 6).

various sources to the measured ambient noise levels (Exh. CPC-5, at 6).

With regard to residential impacts, the Company indicated that the greatest impact would occur at Admirals Hill in Chelsea, a residential neighborhood located across the Island End River, approximately 1800 feet to the east and southeast of the proposed site (Exhs. CPC-2, at 5.4-2, Figure 5.4-1; CPC-4, at 6.3-2). The Company indicated that Admirals Hill also had the highest background noise levels of all residential receptors and that minimum ambient noise levels, would increase by three dBA, from 51 dBA to 54 dBA with operation of the proposed facility (Exh. CPC-4, at 6.3-2). The Company noted that an increase of three dBA is the minimum increase that would be noticeable, and would result in a negligible change in community noise (Tr. 1, at 49-50).[199] Thus, the Company concluded the proposed facility would not have an adverse effect on residential areas surrounding the proposed site (Exh. CPC-5, at 6-7).

With regard to noise impacts at the property line, CPC indicated that noise level increases would range from 11 dBA to 17 dBA, and that the maximum resultant noise level would be 75 dBA at the southeast property line (Exh. CPC-4, at 6.3-3). The Company stated that such a noise level is below the maximum noise level recommended by the EPA for workday exposure at industrial locations (Exh. CPC-5, at 7). CPC added that the facility noise impact at adjacent indoor locations would be negligible due to the noise reduction effect of building walls and existing noise within adjacent industrial facilities (id. at 7-8). The Company provided that noise increases exceeding 10 dBA would be restricted to the IEIP where there are no residences or other sensitive receptors (Exh. HO-RR-1).

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199 The Company noted that another measure of ambient noise is the day-night noise level ("Ldn") which represents the average 24-hour noise level with a ten dBA upward adjustment for nighttime hours (Exh. HO-E-46, at 3, 13). The Company noted that the existing Ldn levels at the residential areas in the vicinity of the proposed facility range from 61 dBA to 68 dBA, and thus are higher than the Ldn of 55 dBA, identified by the EPA as the noise limit requisite to protect public health and welfare in residential areas with an adequate margin of safety (id.). The Company indicated that operation of the proposed facility would not affect the Ldn at any residential receptor except for Admiral Hill, where the Ldn would increase from 61 dBA to 62 dBA (id.).

The Company noted that mitigation measures have been incorporated into the design of the proposed facility in order to decrease facility noise including: (1) a low-noise model air cooled condenser which would achieve a 10 dBA reduction over standard condensers; (2) enclosure of certain equipment; and (3) noise control for the intake of the combustion turbine, cycling air handling units and safety valves (Exhs. CPC-4, at 6.3-4; CPC-5, at 8).

CPC stated that the only guarantee regarding noise increases that would be included in the EPC contract would be the MDEP ten dBA limitation in residential areas (Tr. 6, at 29). However, the Company stated that because the contractor would install the equipment the Company has specified, actual increases at residences and at the property line would reflect projected increases (Tr. 6, at 29-31).[200] The Company stated that unanticipated noise problems would be corrected but that if actual noise increases were slightly higher than projected increases and posed no problems, no action would be taken (id. at 33-34).

In addition to providing an estimate of operational noise impacts, the Company provided an estimate of construction noise at 50 feet from the proposed site and at the nearest residence (Exh. CPC-1, at 10.3-1 to 10.3-3). CPC indicated that pile driving would be the most significant source of construction noise, producing a noise level of 70 dBA at the nearest residence (id. at 10.3-1).[201] However, the Company stated that pile driving would occur for approximately two months in the early part of construction and would be limited to daylight hours only (id.).

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental requirements, including the MDEP's ten-decibel guideline. Altresco Lynn Decision, EFSB 91-102, at 190; 1993 BECo

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200 The Company indicated that, in order to guarantee the noise impacts at projected levels, the EPC contractor would require costly design changes such that projected noise emissions would be substantially lower than currently projected noise emissions (Tr. 6, at 32).

201 CPC indicated that it calculated construction noise impacts as energy-average levels (Exh. CPC-1, at 10.3-1 to 10.3-3). CPC further indicated that noise levels from all construction activities, with the exception of pile driving, would range from 47 dBA to 58 dBA (id.).

Decision, EFSB 90-12/90-12A at 104; Altresco-Pittsfield Decision, 17 DOMSC at 401. In addition, the Siting Board 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. 1993 BECo Decision, EFSB 90-12/90-12A at 104; Enron Decision, 23 DOMSC at 210-211; NEA Decision, 16 DOMSC at 402-403.

Here, the operation of the proposed facility would result in residential receptor noise increases that not only are within the MDEP ten decibel guideline but are less than half that amount. The Siting Board notes that existing ambient residential noise levels are close to the highest levels addressed by the Siting Board in previous reviews of proposed generating facilities. Altresco Lynn Decision, EFSB 91-102, at 188; 1993 BECo Decision, EFSB 90-12/90-12A at 100; Enron Decision, 23 DOMSC at 210-211. Residential noise increases resulting from operation of the proposed facility would be comparable to or lower than the level of residential noise increases resulting from operation of the Enron facility, levels which the Siting Board recognized would be barely perceptible. Enron Decision, 23 DOMSC at 208, 211. However, the Company has indicated that projected noise increases would not be guaranteed by the contractor and that, if actual noise increases were slightly higher than projected increases, and posed no problems, no action would be taken. Given that the existing ambient noise levels in residential areas in the vicinity of the proposed facility are higher than the levels identified by the EPA as requisite to protect public health, increases above the projected levels would not be acceptable.

With respect to increases at the property line, the Siting Board notes that noise increases would be in excess of the MDEP guideline of 10 dBA. The Siting Council previously has accepted proposed property line noise increases in excess of 10 dBA. See, EEC Compliance Decision, 25 DOMSC at 316-318; West Lynn Decision, 22 DOMSC at 93-97. Given the size of the proposed site, the industrial nature of surrounding land use, and the restriction of noise increases over 10 dBA to the IEIP, we find that the noise impacts at the property line would be minimally acceptable.

Finally, with respect to construction noise, the Siting Board notes that construction noise estimates were not presented in a format that allows identification of the increase above ambient levels of construction noise. However, given that the calculated noise levels of most construction activity at the nearest residence would exceed existing daytime noise levels, construction noise could potentially impact nearby residential areas.

Therefore, in order for impacts to community noise levels to be minimized, CPC must meet the following conditions: (1) CPC shall incorporate all proposed mitigation as described herein so that the continuous noise increase from the operation of the proposed facility is no more than three decibels at any residence; (2) CPC shall refrain from conducting construction that generates significant noise before 8:00 a.m.; and (3) CPC shall confine all primary construction activity to between the hours of 6:30 a.m. and 5:30 p.m., Monday through Saturday, except as necessary for structural integrity or safety reasons.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the aforementioned conditions, the environmental impacts of the proposed facility would be minimized with respect to noise impacts.

c. Water Use and Wastewater Discharge

With regard to water use, the Company asserted that facility water usage has been minimized and that there would be no negative impacts on the City of Everett water supply by facility use of municipal water (Company Brief at 143-145).

CPC stated that the proposed facility would use approximately 60,000 gallons per day ("gpd") of potable water from the City of Everett when burning natural gas and approximately 317,000 gpd when burning oil[202] (Exh. CPC-6, at 10). The Company indicated that the proposed facility would tie into the municipal water system via a new connection to an existing water main and that a water supply impact report prepared by the Company confirmed that there would be adequate supply and pressure for all purposes, including firefighting (id. at 11 and attach. DJ-2).

The Company indicated that potable water would be used, primarily, for boiler make-

202 CPC noted that water would be injected into the gas turbine during oil firing in order to reduce NOx emissions (Exh. CPC-6, at 10).

up, and that water conservation measures incorporated into the design of the proposed facility include: (1) dry cooling;[203] (2) one hundred percent condensate recycle;[204] and (3) dry low NOx combustion technology when burning natural gas (id. at 10). The Company stated that additional water conservation measures would be incorporated into facility operation including: (1) partial recycling of the boiler blowdown stream; (2) collection and storage of storm rainfall from the turbine building roof drains and condensate from the air chillers for cleaning and utility applications; and (3) adherence to water conservation practices during plant washdowns (id., at 11; Exh. CPC-3, at 4-3; Tr. 2, at 27-28).

With respect to wastewater, the Company indicated that wastewater discharge from the proposed facility would include approximately 400 gpd of sanitary wastewater, approximately 50,400 gpd of process wastewater, and stormwater (Exhs. CPC-2, at 7.6-1; HO-E-55; HO-E-58). The Company asserted that the wastewater discharges would be acceptable and would not adversely impact the existing sewerage system or the water quality or aquatic ecology of the Mystic River (Company Brief at 151).

With regard to sanitary wastewater discharge, the Company indicated that the facility would connect to an existing sewer line at the DOMAC Terminal and that the limited domestic wastewater that would be generated by the facility operating staff would have no impact on the capacity of the existing sewerage system (Exh. CPC-6, at 19).

The Company indicated that process wastewater, from boiler blowdown and floor drains, and stormwater runoff would be discharged via an existing drainage system to the Mystic River (id. at 18). The Company stated that the overall amount of process wastewater that would be generated by facility operation has been minimized and that facility design incorporates measures to minimize the impacts of process wastewater and stormwater discharge to the Mystic River (id. at 19-20; Exh. HO-E-58). The Company stated that

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203 The Company estimated that a wet cooling tower for a comparable facility would consume approximately one million gpd (Exh. CPC-6, at 10).

204 The Company indicated that all of the hot water delivered to the DOMAC Terminal would be returned to the proposed facility as chilled water and recycled through the surface condenser (Exh. CPC-6, at 10).

process wastewater would be pre-treated prior to discharge and oil/water separators would be located in all areas where floor drain wastewater and stormwater could potentially come into contact with oil or grease (Exh. CPC-6, at 20). In addition, the Company stated that: (1) storage areas for chemicals, oil and grease would be curbed to prevent spills into floor drains; (2) water conservation practices would keep discharge flow to the lowest level possible; and (3) turbine compressor washwater would be disposed off-site to eliminate discharge of detergents (id. at 19; Exh. HO-E-62).

The Company stated that discharge to the Mystic River would require a National Pollution Discharge Elimination System ("NPDES") permit, issued jointly by the MDEP and EPA, which would impose limitations on the quantity and quality of pollutants and would include monitoring requirements (id.; Exhs. CPC-2, at 3.5-1, 7.6-5; HO-E-57). The Company further stated that the proposed facility would be subject to NSPS under the Federal Clean Water Act, which sets specific numerical limitations for various categories of wastewater streams for new steam electric power plants, and that wastewater quality would comply with all such requirements (Exh. CPC-2, at 3.5-1, 7.6-5).

The Company stated that the Mystic River has been classified by state water quality regulations as Class SB which designates the river as suitable for fish, other aquatic life, and for primary and secondary contact recreation (id. at 5.6-3). The Company stated that the facility discharge would comply with Class SB water quality standards with respect to dissolved oxygen, temperature, pH, and oil and grease, and thus would have a negligible impact on the water quality of the Mystic River and aquatic resources of the river (id. at 7.6-5, 7.6-6; Exh. CPC-6, at 18).

The Company has documented that there is an adequate supply of municipal potable water for operation of the proposed facility. Further, the Company has considered water conservation in the design of the proposed facility; water requirements will be minimized by facility features such as dry low-NOx combustors and dry cooling, and use of municipal water will be minimized by recycling process water, stormwater, and air chiller condensate. In addition, with regard to wastewater discharge, the record demonstrates that the capacity of the municipal sewer system is adequate for sanitary wastewater discharge from the proposed facility. Although process wastewater will be discharged into the Mystic River, the record further demonstrates that the water quality and marine resources of the Mystic River would not be negatively impacted. Specifically, the Company has included measures in the design of the proposed facility to prohibit discharge of pollutants such as grease and oil into the Mystic River. In addition, as a result of pretreatment of process water, wastewater discharges will meet all federal and state water quality requirements. Finally, the quality of wastewater will be monitored.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to water use and wastewater discharge.

d. Land Use

The Company asserted that the proposed facility would be consistent with existing land use, City of Everett zoning requirements, area-wide development goals and CZM program policies (Company Brief at 162; Exh. CPC-6, at 13). The Company indicated that the proposed facility would be located within an industrially zoned district and that existing land use in the vicinity includes the DOMAC Terminal, a commercial printing facility, a sand and gravel facility, a cement receiving and distribution center, a petroleum products distribution terminal and electric and natural gas utility facilities (Exh. CPC-2, at 5.1-2). The Company stated that the proposed facility would be compatible with existing businesses and would be located at least 2,000 feet from residential neighborhoods (Exh. CPC-6, at 14).

With regard to City of Everett zoning requirements, the Company indicated that a gas-fired cogeneration facility is not an excluded use for the zoning district encompassing the site (id.). In addition, the Company indicated that the proposed project would meet all zoning requirements except for a stack height limitation of 150 feet (Exh. CPC-6, at 13, 14). However, as noted above in Section II.C.2.a.iii., the Company has received a variance from the Everett Zoning Board of Appeals to construct a 240-foot stack (id. at 13). The Company noted that, once operational, the proposed facility would provide substantial benefits to the City of Everett in terms of tax revenues and additional yearly payments to the City (id. at

15; Tr. 6, at 13-18).

The Company stated that the proposed facility would be consistent with the development goals of the Metropolitan Area Planning Council's Metro Plan 2000[205] which encourages concentrated development in order to minimize (1) the need for new infrastructure and transportation facilities, and (2) the development of open and environmentally sensitive land (Exh. CPC-2, at 7.1-1, 7.1-2). Further, the Company stated that the proposed facility would be consistent with applicable policies of the CZM program including: (1) protection of wetland resources; (2) attainment of national water quality goals; (3) preservation of existing water quality and marine resources; (4) prevention of the exclusion of maritime-dependent industrial uses; and (5) consideration of alternate sites for energy facilities (id., sec. 7.1.2).[206] See Sections II.B.3.d. and III.B.2., above, and Section III.C.2.e., below.

The record demonstrates that the proposed facility would be compatible with the industrial nature of the surrounding land use. In addition, the record demonstrates that the proposed facility would be consistent with City of Everett zoning requirements, area-wide development goals and CZM program policies. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to land use.

e. Wetlands and Waterways

With regard to protection of wetland resources, water quality and marine productivity, the Company stated that there would be no construction within the coastal wetland resource

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205 The Company stated that Metro Plan 2000 is a regional development plan for the 101 communities in the metropolitan Boston region (Exh. CPC-2, at 7.1-1).

206 The Company noted that, although the proposed facility is not located directly on the Mystic River waterfront, policies of the CZM Program would apply to the proposed facility because (1) the project site is located in the Massachusetts Coastal Zone, as mapped under the CZM program, and (2) process water and stormwater will be discharged from the site into drainage facilities which terminate at the shoreline of the Mystic River (Exh. CPC-2, at 7.1-2).

areas of the Mystic River (id. at 7.1-3, 7.1-4, 7.1-5). CPC further stated that, based on expected process water discharges and separation of oil and grease from stormwater, proposed discharges into the Mystic River would have no adverse impacts on the water quality of the river and marine resources (See Section II.B.3.d., above.) (id.).

The record demonstrates that the proposed facility would not impact wetland resources associated with the Mystic River. In addition, as noted above in Section II.B.3.d., above, impacts to the water quality and marine resources of the Mystic River would be minimized. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to wetlands and waterways.

f. Safety

The Company addressed safety concerns related to: (1) the storage and use of potentially hazardous substances at the proposed facility; (2) location of the proposed facility in close proximity to the LNG terminal; and (3) pre-existing site contamination. The Company concluded that the construction and operation of the proposed facility would not present a risk to public safety (Company Brief at 158-161, 166; Exh. CPC-2, at section 7.9).

With regard to the storage and use of potentially hazardous substances, the Company indicated that substantial quantities of ammonia would be required, primarily for operation of the SCR system, and that moderate quantities of other hazardous substances would be required for various facility processes and maintenance (Exhs. CPC-1, at 11.9-4; CPC-2, at 7.9-7). The Company indicated that all areas where chemical substances and oils would be stored or used would be designed with containment areas such that any spilled materials could be collected and transported off-site for disposal in accordance with regulatory requirements (Exh. CPC-1, at 11.9-4).

The Company stated that an independent safety assessment conducted for the City of Everett, evaluated worst-case accident scenarios due to the storage of ammonia and proximity of the proposed facility to the DOMAC Terminal and concluded that the proposed facility presented little, if any, risk to the surrounding properties (Exh. CPC-3, at 7-59, app. F). The Company expressed its willingness to implement all recommendations cited in the safety assessment such that potential risks would be reduced to the greatest extent possible (id. at 7-59; Exh. HO-E-67).[207]

With respect to the use of ammonia, CPC stated that aqueous ammonia[208] would be transported to the site via roadways (Exh. CPC-2, at 7.9-4, 7.9-5). The Company maintained that the design of the ammonia storage and piping systems would minimize risks of release (id. at 7.9-5 through 7.9-7). The Company explained that ammonia would be stored in two 9,500 gallon tanks that would be placed within a containment dike capable of holding the entire contents of both tanks (Exhs. CPC-1, at 11.9-3; HO-B-12, attach. 5, at 3). The Company noted that the tanks and floor of the dike would contain layers of hollow plastic spheres that would reduce the surface area of liquid exposed to the air and thus, minimize evaporation to the atmosphere (id.). CPC added that pumps used to transport the ammonia to the injection system would be located within the diked area and pipelines would be routed to minimize risk of damage by vehicles and routine maintenance (Exh. CPC-2, at 7.9-6, 7.9-7).

In addition, the Company evaluated the potential for public exposure to harmful levels of ammonia vapors from an ammonia tank failure (Exh. HO-B-12, attach. 2A).[209] Based on a dispersion analysis, the Company determined that harmful concentrations would not

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207 The safety assessment recommendations include: (1) installation of pressure relief devices in the ammonia storage tanks; (2) installation of gas detectors along the perimeter of the proposed facility; and (3) use of explosion-proof electrical equipment close to the boundary of the DOMAC Terminal (Exh. CPC-3, at app. F.).

208 The Company indicated that SCR systems can be operated with either anhydrous or aqueous ammonia (Exh. CPC-2, at 7.9-4). The Company further indicated that, although anhydrous ammonia would be less expensive and easier to handle and vaporize, aqueous ammonia would be used at the proposed facility because it would present a lower risk of public exposure to acute toxic concentrations in the event of a spill (id. at 7.9-4, 7.9-5).

209 CPC indicated that the National Institute for Occupational Safety and Health has identified a 30-minute exposure to ammonia concentrations of 500 ppm as Immediately Dangerous to Life and Health ("IDLH concentrations") (Exh. HO-B-12, attach. 5, at 2-3).

reach the nearest inhabited areas to the facility site and that on-site areas would easily be evacuated or ventilated (id. at 4-5).[210] Thus, the Company concluded that the design of the proposed facility would be adequate to ensure public safety in the event of an accidental release of ammonia (id.). In addition, the Company will prepare an emergency response plan, in collaboration with local authorities which will include specifications for prevention practices and emergency contacts (Exh. CPC-2, at 7.9-10 to 7.9-12).

With regard to concerns relating to the location of the proposed facility in close proximity to the DOMAC Terminal, CPC maintained that safety features incorporated into the design of the proposed facility would ensure that no event at the proposed facility would cause an adverse event at the DOMAC Terminal and that the impact of an event at the DOMAC Terminal would not be aggravated by the presence of the proposed facility (Exh. CPC-3, at 7-57, 7-58). The Company stated that such safety features include location and orientation of major equipment, extensive fire protection systems, barrier walls, automatic fuel shut-off valves, and automatic shut-down of the proposed facility where concentrations of natural gas are detected at the property line (id. at 7-58). The Company also stated that since both the primary and back-up fuels would be available from off-site pipelines, no storage for flammable fuels at the site would be required (Exh. HO-E-66).

Finally, CPC asserted that consideration of site contamination has been incorporated into construction plans and facility design in order to ensure that no adverse health or safety impacts would be created by construction of the proposed facility (Company Brief at 161).[211] The Company indicated that an initial evaluation of the site, performed in

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210 CPC determined that under worst-case weather conditions, the maximum distance at which the IDLH concentration is predicted would be 164 feet (Tr. 3, at 13-15). The Company noted that, although a small portion of Commercial Street is within 164 feet, a passing vehicle would not be exposed to ammonia vapor for 30 minutes (Exh. HO-B-12, attach. 5, at 4). In addition, the Company noted that the nearest inhabited spaces to the site are approximately 250 to 300 feet to the southeast and southwest (id.).

211 The Company noted that the proposed site is located within an area that has (continued...)

accordance with Phase I of the Massachusetts Contingency Plan ("MCP") confirmed the existence of hazardous substances within the site subsurface and groundwater (Exh. CPC-1, at 9.6-2, 9.6-3).[212] The Company stated that preliminary construction plans reflect the nature and distribution of pollutants such that worker exposure and redistribution of contaminants beneath the site would be avoided (id. at 10.6-1, 10.6-2). Specifically, the Company stated that it would (1) cap the entire site with clean fill to provide additional vertical separation between the new facility and subsurface contamination, and (2) use steel "H" piles for foundations to minimize movement of existing soils and alteration of groundwater paths (id. at 10.6-1; Exhs. HO-E-8; HO-E-71). In addition, the Company stated that excavations for on-site utilities would be above the existing contaminated soil and groundwater but that removal of two abandoned underground storage tanks and installation of off-site utilities would possibly require removal of contaminated soils and groundwater (Exhs. CPC-1, at 10.6-2, 10.6-3; HO-E-71). However, the Company maintained that protocol for the removal of all contaminated substances would be established prior to excavation to protect worker health and safety and that all contaminated substances would be disposed in accordance with applicable regulations (Exh. CPC-1, at 10.6-2, 10.6-3). In addition, the Company indicated that the existing warehouse contains asbestos floor tile which would be removed prior to the demolition of the structure in accordance with applicable regulations (id. at 10.6-2). The Company added that as part of the MCP, all construction activities would be subject to a site specific Health and Safety Plan (Exh. CPC-

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[211](...continued)
historically been used for a variety of industrial activities including a coal gasification plant and that numerous environment investigations have revealed subsurface contamination at and near the proposed site (Exh. CPC-2, at 9.6-1).

[212] CPC explained that at sites where contamination has been identified, G.L. Chapter 21E requires that the MDEP be notified and an evaluation made as to whether the contamination represents a risk to human health and the environment and that the MCP is the regulatory process that guides the investigation of a contaminated site from the preliminary assessment through eventual remediation (Exh. CPC-2, at 3.6-1, 9.6-2).

2, at 6.7-3).

The Company stated that it is continuing to proceed through the MCP process of additional site evaluation, characterization of risk assessment, and development of remediation alternatives which would serve as the basis of its final engineering design (Tr. 2, at 5). CPC noted that the MDEP has classified the site as a "non-priority disposal site" and has granted a waiver of approval requirements (Exh. HO-RR-4). Thus, the Company indicated the MDEP would monitor completion of the MCP process but that the Company would be allowed to proceed through the MCP process without MDEP approval of each phase (id.; Exh. HO-E-6).

The record demonstrates that the design of the proposed facility includes safety features to: (1) avert spills of hazardous materials; (2) contain any accidental spills of hazardous materials; and (3) ensure that operation of the proposed facility in close proximity to the LNG terminal would not present hazardous conditions. In addition, the Company will implement all recommendations specified in an independent safety assessment conducted for the City of Everett and will develop an Emergency Response Plan in conjunction with local authorities, similar to plans found acceptable by the Siting Board in previous reviews of generating facilities. See, Altresco Lynn Decision, EFSB 91-102, at 204; 1993 BECo Decision, EFSB 90-12/90-12A at 137; Enron Decision, 23 DOMSC at 220.

With respect to existing site contamination, the record demonstrates that, consistent with state requirements, the Company will take appropriate measures during construction of the proposed facility to avoid potential hazards resulting from existing site contamination. Construction plans for the proposed facility will incorporate measures to ensure that worker exposure to subsurface contaminants is avoided and movement of existing subsurface contaminants is minimized. Where removal of contaminated soils and groundwater will be required, protocols for excavation will be established prior to excavation to protect worker health and safety and removal and disposal of hazardous materials will be in accordance with applicable regulations. In addition, site remediation and final engineering design will be monitored by the MDEP and a site-specific Health and Safety Plan will encompass all construction-related activities.

Accordingly, based on the foregoing, with implementation of the aforementioned mitigation measures, the Siting Board finds that the environmental impacts of the proposed facility will be minimized with respect to safety.

g. Traffic

CPC asserted that the construction and operation of the proposed facility would not result in a significant impact to traffic in the vicinity of the proposed facility (Company Brief at 154-156). In order to assess the impact of construction and operation of the proposed facility on traffic, the Company provided an analysis of the existing and anticipated traffic conditions at the intersection of Route 99 and Dexter Street in accordance with recognized Level of Service ("LOS") standards (Exh. CPC-1, at secs. 9.7, 10.7, 11.7).[213] The Company indicated that Dexter Street would provide direct access to the proposed site from Route 99 and that the existing (1990) LOS level at the intersection was level F for both the morning commuter peak hour of 7:30 a.m. to 8:30 a.m. and the afternoon commuter peak hour of 4:30 p.m. to 5:30 p.m. (id. at 9.7-1, 9.7-6; Exh. CPC-2, at 5.2-2). The Company's analysis demonstrated that the LOS would remain at level F under 1993 no-build and 1993 construction conditions, but that delays would be greater under construction conditions than no-build conditions (Exh. CPC-1, at 10.7-4). The Company's analysis also indicated that the LOS would remain at level F under 1995 no-build and 1995 operation conditions but that, due to the limited number of daily employee trips, delays at the intersection would be similar for no-build and operation conditions (id. at 11.7-1).

The Company maintained that existing traffic conditions reflect the areas commercial and industrial land uses (id. at 9.7-3). In addition, CPC stated that traffic impacts would be minimal because the construction workshift of 7:00 a.m. to 4:00 p.m. would fall outside

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213 CPC indicated that LOS refers to the quality of traffic flow along roadways and at intersections and is described in terms of Levels A through F, where A represents the best possible conditions and F represents forced-flow or failing conditions (Exh. CPC-1, at 9.7-3). The Company noted that LOS D or better is considered acceptable in an urbanized area (id.).

commuter peak hours (Exh. CPC-2, at 6.6-2). However, to minimize traffic impacts during construction, the Company indicated that: (1) the construction work shift would be scheduled to avoid arrivals and departures during the peak commuter hours; (2) truck traffic would be limited by spreading the truck arrival schedule over the construction work shift; and (3) where possible, construction materials would be delivered by rail or barge (Exh. CPC-3, at 8-1, 8-2). In addition, the Company indicated that it would take measures to encourage workers to use alternate routes to the site to avoid the Route 99/Dexter Street intersection, including: (1) provision of a limited number of parking spaces to encourage car pooling and public transportation; (2) location of smaller parking areas to the north and west to split the flow of commuting traffic to the site; (3) restriction of the flow of traffic on Rover Street; and (4) provision of shuttle bus service from public transportation and remote parking areas (id. at 8-2).

The record demonstrates that the intersection that provides direct access to the proposed site currently operates at an unacceptable LOS during the morning and afternoon peak hours and that delays at the intersection would increase during construction of the proposed facility. However, the Company has proposed a number of mitigation measures that would restrict traffic to the site during peak hours and encourage alternative routes to the site. Therefore, in order to minimize traffic impacts during peak hours, the Siting Board requires that CPC: (1) schedule the construction work shift to avoid arrivals and departures during the peak commuter hours of 7:30 a.m. to 8:30 a.m. and 4:30 p.m. to 5:30 p.m.; (2) schedule truck arrivals to be spread over the construction work shift; and (3) where possible, to arrange for construction materials to be delivered by rail or barge. In addition, the Siting Board requires that the Company, in consultation with the City of Everett, implement measures that would encourage the use of public transportation and alternative routes to the site by construction workers. Accordingly, based on the foregoing, the Siting Board finds that with the implementation of the aforementioned conditions, the environmental impacts of the proposed facility would be minimized with respect to traffic impacts.

h. Visual

CPC asserted that the visual impacts of the proposed facility are acceptable and have been adequately minimized (Company Brief at 156-158). Given that the setting in which the proposed project would be viewed is predominately industrial, the Company maintained that the proposed facility would not alter the basic visual character of the area and would be visually consistent in terms of size, scale and form with the existing visual elements of the area (id.). The Company provided that the most prominent features of the proposed facility would be the turbine building, the HRSG, the air cooled condenser which would range in height from 65 to 85 feet, and the exhaust stack which would be 240 feet tall (Exh. CPC-2, at 7.1-10). The Company indicated that the most prominent structures in the visual setting of the proposed facility would be the existing LNG tanks which are approximately 200 feet tall and the Mystic station, which includes 200-foot buildings and 500-foot stacks, and further indicated that other facilities immediately adjacent to the proposed facility site would include cement silos, towers of a manufacturing facility, warehouse buildings, and scrap metal, sand and gravel storage piles, (id.).

CPC stated that it conducted a visual survey of the project area to determine the locations of concern regarding the visual impacts of the proposed facility (id.). The Company prepared representations of expected views of the proposed facility from five visual receptors and asserted that such representations demonstrate that the facility would not have an adverse impact on views in the area (Company Brief at 157-158).

The record demonstrates that the proposed facility is located within an industrial area, would be consistent in terms of size, scale and form with the existing structures in the area and, as such, would not alter the visual character of the area. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to visual impacts.

i. Electric and Magnetic Fields[214]

The Company asserted that EMF impacts of the transmission line that would interconnect the proposed facility to the existing Mystic Substation would be minimal (Company Brief at 161-162; Exh. CPC-1, at 11.9-5). The Company indicated that a 2,500-foot long, underground, 345 kV transmission line would be constructed along a private roadway, within a new conduit for approximately 1,000 feet and within an existing, abandoned gas pipeline for the remaining 1,500 feet (Exh. CPC-1, at 11.9-5 and figure 3.3-4). The Company indicated that the chosen route is the shortest route from the proposed facility to the Mystic substation, is relatively straight and would traverse public ways or property owned by the proponent or Boston Edison (Exh. HO-E-65). The Company further indicated that the proposed route abuts industrial uses (Exh. CPC-2, figures 2.1-2, 2.2-4).

The Company stated that electric fields would be shielded by the overlying fill material and, as such, the transmission line would not generate above-ground electric fields (Exh. HO-E-64). The Company also stated that magnetic fields at ground level would be minimal because the transmission line would be installed within a steel pipe which would shield the magnetic fields (id.).

The proposed facility would be interconnected via a 345 kV underground line to the bulk transmission system approximately one-half mile from the proposed site. Based on the record, there would be no electric fields and only minimal magnetic fields at ground level along the route of the interconnection line between the proposed facility and the Mystic Substation. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to EMF.

j. Conclusion

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility, including mitigation measures and facility

214 Electric and magnetic fields produced by the presence of voltage and the flow of current are collectively known as electromagnetic fields or "EMF."

design, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized as itemized above.

The Siting Board has found that, based on the above mitigation measures, conditions, and facility design, the environmental impacts of the proposed facility would be minimized with respect to air quality (with the exception of CO_2), water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety and EMF.

3. Cost Analysis of the Proposed Facilities

In this section the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance would be achieved between environmental impacts and cost.

CPC provided a construction cost estimate of $200 million or $851/kW in 1995 dollars (Exh. CPC-1, at 8-2). The Company indicated that this cost estimate reflects site specific conditions and current information regarding: (1) the Boston area labor market; (2) financial projections of interest rates and short- and long-term debt rates; and (3) equipment supplier pricing estimates including proposed environmental control technologies (id. at 8-1; Exhs. HO-C-4; HO-C-5; HO-E-52; HO-E-76).[215] CPC provided itemized estimates of the construction and engineering aspects of the project developed by the EPC contractor (Exhs. HO-C-1; HO-C-2). CPC also provided additional itemized estimates including development costs, contingency funds, off-site facility costs, start-up costs, and interest payments (id.). The Company also provided estimated annual operating expenses for the 1996 to 2015 time period, which included fuel costs, operation and maintenance costs, insurance, site costs and property taxes (Exh. CPC-21, attach. RLC-5).

The Company maintained that technological aspects of the project offer significant cost advantages over comparatively sized, generic, gas-fired combined-cycle facilities (Exh. CPC-1, at 5.2-2, 5.2-3). CPC explained that the advanced, high temperature, gas-turbine

215 The Siting Board notes that cost estimates were current as of the date of the Company's filing, March 1, 1991.

combined-cycle technology would generate approximately twice the megawatt output of a conventional gas turbine and also is more fuel efficient than a conventional gas turbine, thereby reducing capital costs per unit output by approximately 15 percent and reducing fuel requirements per unit output by approximately ten percent (id. at 5.2-2).[216] In addition, CPC explained that the project's thermal energy output would be produced without additional fuel cost or loss of power production because DOMAC can utilize thermal energy in the form of hot water rather than low-to medium-pressure steam (id.). CPC further explained that the dry low-NOx combustor technology, which would eliminate the need for water or steam injection to control NOx emissions during natural gas firing, would reduce water consumption and water treatment costs (id.).[217]

CPC also maintained that the location of the proposed site would offer cost advantages (id. at 5.2-3). CPC stated that location of the proposed site adjacent to the DOMAC Terminal would reduce fuel costs because natural gas pipeline and local distribution company transportation charges would not be incurred (id.).[218] In addition, the Company stated that interconnection costs for thermal energy delivery would be minimized (id.). CPC stated that further cost advantages would result from the location of the proposed site in close proximity to both the back-up fuel oil supply and Mystic Substation, in that (1) fuel oil storage would not be required on-site, and (2) construction of less than one mile of transmission line would be required (id.).

Finally, the Company indicated that the capital cost of the proposed project would compare favorably to the capital cost of a generic, advanced gas turbine combined-cycle

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216 The Company estimated that fuel cost savings would be approximately five million dollars per year (Exh. CPC-1, at 5.2-2).

217 CPC indicated that an additional cost effective technological aspect of the proposed facility is the inlet air chiller which would increase the summer power output of the proposed facility by as much as 30 MW for a cost of approximately five million dollars (Tr. 6, at 39-40). See Section III.C.2.a.ii., above.

218 The Company estimated that cost of delivered fuel to the proposed project would be approximately $.40/MMBtu less than the price of delivered natural gas to a typical project (Exh. CPC-1, at 5.2-3).

facility, based on data provided by the Electric Power Research Institute (Exh. HO-C-3).

The Company has provided estimates of the overall costs of the proposed facility and has specified cost advantages due to unique technological and siting aspects of the proposed facility. Accordingly, based on the foregoing, the Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

4. Conclusions on the Proposed Facility

In this section, we review the consistency of the proposed facility with our overall review standard, requiring that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as trade-offs between these environmental impacts and cost.

The Siting Board has found that based on the implementation of the above mitigation measures and facility design, and with the implementation of the conditions specified in Sections III.C.b. and III.C.f., the environmental impacts of the proposed facility would be minimized with respect to water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, and EMF. Further, the Siting Board has found that, based on the implementation of the above mitigation measures and facility design, the environmental impacts of the proposed facility would be minimized with respect to air quality impacts, with the exception of CO_2 impacts.

In addition, the Siting Board has found that CPC provided sufficient information on the costs of the proposed project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

The record indicates that there are no significant issues involving the balance among water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, safety, EMF, and air quality impacts other than CO_2, nor between any of these concerns and cost. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, safety, EMF, and air quality impacts, other than CO_2, consistent with minimizing cost and other environmental impacts.

With respect to CO_2 emissions, the Siting Board has found that the Company did not establish that the CO_2 emissions impacts of the proposed facility would be minimized. Thus, the Siting Board considers whether CPC's proposed level of CO_2 mitigation or a higher level of CO_2 mitigation would allow CPC to establish that the CO_2 emissions of the proposed facility would be minimized consistent with minimizing cost.

In a recent review of a natural gas-fired facility, the Siting Board found that the appropriate level of CO_2 offsets should bear a reasonable relationship to the level of CO_2 offsets required in the EEC Compliance Decision, even though the filing predated the Siting Council's establishment of general criteria for CO_2 mitigation set forth in the EEC Compliance Decision. Altresco Lynn Decision, EFSB 91-102, at 210-211. The Siting Board noted that little or no tree clearing would be required for construction of the proposed facility in that review and thus, the Siting Board found that the appropriate level of CO_2 offsets would be 0.348 percent of the facility CO_2 emissions -- equivalent to the offset percentage required in the EEC Compliance Decision, after taking into account required on-site tree clearing. See n.191, above.

Here, the proposed facility would emit up to 943,000 tpy of CO_2[219] and construction of the proposed facility also would require little or no on-site tree clearing. Thus the Siting Board finds that a net offset requirement of 0.348 percent of maximum CO_2 emission also would be appropriate in this case, resulting in an offset requirement of 3,282 tpy for the proposed facility.

Based on the assumption that a planted tree offsets 0.75 tpy of CO_2, planting 4,376 trees would offset 3,282 tpy of CO_2. With respect to tree planting costs, the Siting Board has recognized a cost of $100 per tree under the MASS ReLeaf program. Altresco Lynn Decision, EFSB 91-102, at 212; EEC (remand) Decision, EFSB 90-100R at 350. Based on a cost of $100 per tree, a contribution of $437,600 would be required to provide the necessary

219 As noted above, CO_2 emissions of 943,000 tpy reflect 30 days of oil firing.

offsets.[220]

As part of considering a possible increase in CPC's proposed CO_2 mitigation level, the Siting Board considers the possible effect of the cost of any such additional mitigation on project viability and the proponent's ability to mitigate other environmental impacts. Altresco Lynn Decision, EFSB 91-102, at 213; EEC Compliance Decision, 25 DOMSC at 364-365. The Siting Board notes that a cost of $437,600 to mitigate 0.348 percent of the facility's CO_2 emissions would be approximately one-fifth of a percent of the total estimated cost of the proposed facility.[221] Based on cost information contained in the record, the Siting Board notes that an offset cost of $437,600 to as much as $656,400 would have no apparent effect on the viability of the project or the Company's ability to mitigate other environmental impacts.

Thus, the Siting Board finds that implementation by CPC of a CO_2 mitigation plan to provide, in equal installments over the first five years after start-up or sooner, CO_2 offsets for at least 0.348 percent of the total CO_2 emissions from the proposed facility, using the approach presented by CPC -- that is MASS ReLeaf -- would be consistent with an adequate minimization of CO_2 emissions impacts from the proposed facility, consistent with the minimization of cost. Should CPC choose as an alternative to implementation of the above CO_2 mitigation approach, to present a modified CO_2 mitigation plan and supporting analysis that includes a different mix of approaches for providing the required offsets of 0.348

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220 The Company estimated a cost of $150 per tree under MASS ReLeaf. Based on the Company's estimated cost per tree, a contribution of $656,400 to MASS ReLeaf would be required to provide the necessary offsets.

221 In the Altresco Lynn Decision, EFSB 91-102, at 213, the cost to mitigate 0.348 percent of the facility's CO_2 emissions was less than one-sixth of a percent of the total estimated cost of that proposed facility while in the EEC Compliance Decision, 25 DOMSC at 327, the cost of required CO_2 mitigation was approximately one-thrid of of a percent of project cost. The Siting Board notes that CO_2 emissions increase with oil-firing and that the proposed CPC facility could use a maximum of 30 days of oil per year whereas the proposed facility reviewed in the Altresco Lynn Decision would use a maximum of five days of oil per year. EFSB 91-102, at 1. See Section II.B.3.a., above.

percent of total CO_2 emissions other than the MASS ReLeaf approach alone, the Siting Board will review such plan and analysis to determine if it is consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost.

Accordingly, the Siting Board finds that with implementation of the requirement that the Company provide offsets of at least 0.348 percent of total CO_2 emissions from the proposed facility, the environmental impacts of the CO_2 emissions from the proposed facility would be minimized consistent with minimizing cost.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H to 69Q, to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Sections II.A, II.B, II.C, III.B and III.C, above, the Siting Board has found that upon compliance with the condition regarding signed and approved PPAs, the Company will have established need for the proposed project. Further, the Siting Board has found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and that upon compliance with the listed conditions, CPC will have established that its proposed project is reasonably likely to be a viable source of energy. The Siting Board has also found that CPC has considered a reasonable range of practical facility siting alternatives, and that with implementation of the listed conditions relative to noise, traffic and CO_2 offsets the environmental impacts from the proposed facility would be minimized consistent with minimizing cost.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.A.5, II.C, III.C.2, and III.C.4, above, and listed below, the construction and operation of the proposed project and ancillary facilities will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Further, as evidenced by the above discussions and analyses, the Siting Board agrees with the Company that the proposed project is consistent with various environmental protection and resource use and development policies of the Commonwealth, including those policies encouraging the development of cogeneration facilities at existing industrial sites and the use of natural gas as a fuel for power generation, fuel diversity, and environmental protection purposes. See Section I.A, above.

Accordingly, the Siting Board APPROVES the petition of Cabot Power Corporation to construct a 235 MW bulk generating facility and ancillary facilities in Everett, Massachusetts subject to the following conditions.

(A) In order to establish that the proposed project will provide a necessary energy supply for the Commonwealth, and that its proposed project is financiable, the Company shall, within four years from the date of this conditional approval, submit to the Siting Board signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's electrical output.

(B) In order to establish that the proposed project has access to the regional transmission system and, therefore, will be capable of meeting performance objectives, the Company shall provide the Siting Board with a signed copy of an interconnection agreement between CPC and BECo for evidence of the proposed project's access to the regional transmission system.

(C) In order to establish that the proposed project has a fuel acquisition strategy which ensures a low-cost reliable source of energy, the Company shall provide a copy of the contract or any other agreement between the Company and Exxon or any of Exxon's successors, transferees or assigns, regarding the supply of distillate oil to the proposed project.

At such time as the Company provides the Siting Board with the information listed above, the Siting Board shall review the information and determine if the Company has complied with each condition. The Company will not receive final approval of its project until it complies with these conditions.

In addition, the Company shall comply with the following conditions during construction and operation of the proposed facility.

(D) In order for impacts to community noise levels to be minimized, CPC shall: (1) incorporate all proposed mitigation as described in Section III.C.b, above, so that the continuous noise increase from the operation of the proposed facility is no more than three decibels at any residence; (2) refrain from conducting construction that generates significant noise before 8:00 a.m.; and (3) confine all primary construction activity to between the hours of 6:30 a.m. and 5:30 p.m., Monday through Saturday, except as necessary for structural integrity or safety reasons.

(E) In order to minimize traffic impacts during peak hours, CPC shall:
(1) schedule the construction work shift to avoid arrivals and departures during the peak commuter hours of 7:30 a.m. to 8:30 a.m. and 4:30 p.m. to 5:30 p.m.;
(2) schedule truck arrivals to be spread over the construction work shift; (3) where possible, arrange for construction materials to be delivered by rail or barge; and (4) in consultation with the City of Everett, implement measures that would encourage the use of public transportation and alternative routes to the site by construction workers.

(F) In order to establish that CO_2 emissions are minimized, CPC shall implement a CO_2 mitigation plan to provide, in equal installments over the first five years after start-up or sooner, CO_2 offsets for at least 0.348 percent of the total CO_2 emissions from the proposed facility using the approach presented by CPC -- the MASS ReLeaf program; or in the alternative, present a modified CO_2 mitigation plan and supporting analysis that includes a different mix of approaches for providing the required offsets of 0.348 percent of total CO_2 emissions.

In the event that the Company provides the Siting Board with an alternative mitigation plan and supporting analysis, the Siting Board will review such plan and analysis to determine if it is consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost.

In addition, the Siting Board 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 as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting board to make these determinations.

Robert P. Rasmussen

Robert P. Rasmussen
Hearing Officer

Dated this 9th day of March, 1994

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of March 9, 1994 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, EFSB/DPU); Barbara Kates-Garnick (Commissioner, DPU); Mary Clark Webster (Commissioner, DPU); Stephen Remen (for Gloria C. Larson, Secretary of Economic Affairs); Andrew Greene (for Trudy Coxe, Secretary of Environmental Affairs); Joseph Faherty (Public Member); and William Sargent (Public Member).

Kenneth Gordon
Chairman

Dated this 9th day of March, 1994

TABLE 1

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1996

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	1,487	1,487	1,715
Ref	Base	1,154	1,154	1,382
Mult Regr		468	468	696
End Yr Lin	High	10	10	238
High Low Av	High	(37)	(37)	191
End Yr Lin	Base	(324)	(324)	(96)
High Low Av	Base	(371)	(371)	(143)
Lin Regr		(682)	(682)	(454)
CAGR Regr		(2,005)	(2,005)	(1,777)
High Demand	High	(3,398)	(3,639)	(3,411)
High Demand	Base	(3,732)	(3,973)	(3,745)

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	976	1,152	1,407
Ref	Base	747	757	1,012
Mult Regr		(472)	(296)	(41)
End Yr Lin	High	(592)	(499)	(244)
High Low Av	High	(971)	(878)	(623)
End Yr Lin	Base	(987)	(894)	(639)
Lin Regr		(1,326)	(1,233)	(978)
High Low Av	Base	(1,366)	(1,273)	(1,018)
CAGR Regr		(2,919)	(2,826)	(2,571)
High Demand	High	(5,358)	(5,247)	(4,992)
High Demand	Base	(5,753)	(5,642)	(5,387)

TABLE 1 (page 2)

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	180	356	612
Ref	Base	(273)	(97)	159
End Yr Lin	High	(1,303)	(1,127)	(871)
Mult Regr		(1,381)	(1,205)	(949)
End Yr Lin	Base	(1,756)	(1,580)	(1,324)
High Low Av	High	(1,784)	(1,608)	(1,352)
Lin Regr		(2,079)	(1,903)	(1,647)
High Low Av	Base	(2,237)	(2,061)	(1,805)
CAGR Regr		(3,966)	(3,790)	(3,534)
High Demand	High	(6,502)	(6,341)	(6,085)
High Demand	Base	(6,955)	(6,794)	(6,538)

1999

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	(577)	(401)	(119)
Ref	Base	(1,085)	(909)	(627)
End Yr Lin	High	(1,804)	(1,664)	(1,382)
Mult Regr		(2,224)	(2,048)	(1,766)
End Yr Lin	Base	(2,347)	(2,171)	(1,889)
High Low Av	High	(2,469)	(2,293)	(2,011)
Lin Regr		(2,658)	(2,482)	(2,200)
High Low Av	Base	(2,976)	(2,800)	(2,518)
CAGR Regr		(4,865)	(4,689)	(4,407)
High Demand	High	(7,507)	(7,346)	(7,064)
High Demand	Base	(8,014)	(7,853)	(7,571)

TABLE 1 (page 3)

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	(1,134)	(958)	(670)
Ref	Base	(1,699)	(1,523)	(1,235)
End Yr Lin	High	(2,395)	(2,219)	(1,382)
End Yr Lin	Base	(2,960)	(2,784)	(2,496)
High Low Av	High	(2,990)	(2,814)	(2,526)
Mult Regr		(3,113)	(2,937)	(2,649)
Lin Regr		(3,255)	(3,079)	(2,791)
High Low Av	Base	(3,555)	(3,379)	(3,091)
CAGR Regr		(5,807)	(5,631)	(5,343)
High Demand	High	(8,300)	(8,139)	(7,851)
High Demand	Base	(8,865)	(8,704)	(8,416)

Notes: Low supply, base supply, high supply cases include 83 MW -- the committed capacity of Enron.

Sources: Exhs. CPC-9, exh. RLC(31).

TABLE 2

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1996

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	1,487	1,487	1,781
Ref	Base	1,378	1,378	1,672
Mult Regr		468	468	762
End Yr Lin	High	10	10	304
High Low Av	High	(38)	(38)	256
End Yr Lin	Base	(96)	(96)	198
High Low Av	Base	(147)	(147)	147
Lin Regr	Base	**(682)**	**(682)**	**(388)**
CAGR Regr		**(2,005)**	**(2,005)**	**(1,711)**

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	976	1,152	1,473
Ref	Base	851	1,027	1,348
Mult Regr		**(472)**	**(296)**	25
End Yr Lin	High	**(675)**	**(499)**	(178)
End Yr Lin	Base	**(801)**	**(625)**	**(304)**
High Low Av	High	**(1,055)**	**(879)**	**(558)**
High Low Av	Base	**(1,181)**	**(1,005)**	**(684)**
Lin Regr		**(1,409)**	**(1,233)**	**(912)**
CAGR Regr		**(3,002)**	**(2,826)**	**(2,505)**

TABLE 2 (page 2)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	287	463	785
Ref	Base	146	322	644
End Yr Lin	High	(1,189)	(1,013)	(691)
Mult Regr		(1,267)	(1,091)	(769)
End Yr Lin	Base	(1,336)	(1,160)	(838)
High Low Av	High	(1,669)	(1,493)	(1,171)
High Low Av	Base	(1,832)	(1,656)	(1,334)
Lin Regr		(1,962)	(1,786)	(1,464)
CAGR Regr		(3,841)	(3,665)	(3,343)

1999

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	(356)	(180)	168
Ref	Base	(510)	(334)	14
End Yr Lin	High	(1,608)	(1,432)	(1,084)
End Yr Lin	Base	(1,775)	(1,599)	(1,251)
Mult Regr		(1,990)	(1,814)	(1,466)
High Low Av	High	(2,233)	(2,057)	(1,709)
High Low Av	Base	(2,387)	(2,211)	(1,863)
Lin Regr		(2,419)	(2,243)	(1,895)
CAGR Regr		(4,608)	(4,432)	(4,084)

TABLE 2 (page 3)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	High	**(796)**	**(620)**	**(266)**
Ref	Base	**(963)**	**(787)**	**(433)**
End Yr Lin	High	**(2,042)**	**(1,866)**	**(1,515)**
End Yr Lin	Base	**(2,228)**	**(2,052)**	**(1,698)**
High Low Av	High	**(2,628)**	**(2,452)**	**(2,098)**
Mult Regr		**(2,750)**	**(2,574)**	**(2,220)**
High Low Av	Base	**(2,796)**	**(2,620)**	**(2,266)**
Lin Regr		**(2,890)**	**(2,714)**	**(2,360)**
CAGR Regr		**(5,411)**	**(5,235)**	**(4,881)**

NOTES: Bold signifies deficiency of at least 235 MW.

Table 2 incorporates the following changes from Table 1: (1) Reserve margins adjusted as follows: 22 percent in 1996 and 1997, 21.5 percent in 1998, 21 percent in 1999, and 20.5 percent in 2000; (2) base DSM case discounts DSM increment over 1991 by 8.4 percent; (3) high supply case includes uncommitted portion of MASSPOWER and Enron.

SOURCES: Exhs. CPC-9, exhs. RLC-20(c), RLC-22, RLC-28; HO-RR-15 at 1; HO-RR-9.

TABLE 3

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-1998

1996

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref High	(682)	(50)	103	(412)	200
Ref Base	(822)	(190)	(37)	(552)	60
Ref Low	(950)	(317)	(164)	(679)	(67)
EndYr High	(961)	(328)	(175)	(690)	(78)
EndYr Base	(1,049)	(417)	(264)	(778)	(167)
ExVal High	(1,054)	(421)	(268)	(783)	(171)
EndYr Low	(1,118)	(485)	(332)	(847)	(235)
ExVal Base	(1,194)	(561)	(408)	(923)	(311)
ExVal Low	(1,321)	(689)	(536)	(1,050)	(439)
Lin Regr	(1,334)	(701)	(548)	(1,063)	(451)
CAGR Regr	(1,779)	(1,147)	(994)	(1,508)	(897)

1997

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref High	(871)	(239)	29	(664)	11
Ref Base	(1,039)	(407)	(139)	(831)	(157)
Ref Low	(1,188)	(556)	(288)	(980)	(306)
EndYr High	(1,222)	(590)	(322)	(1,014)	(340)
EndYr Base	(1,335)	(703)	(435)	(1,127)	(453)
ExVal High	(1,368)	(736)	(468)	(1,160)	(486)
EndYr Low	(1,423)	(791)	(523)	(1,215)	(541)
ExVal Base	(1,536)	(903)	(636)	(1,328)	(653)
Lin Regr	(1,552)	(920)	(652)	(1,344)	(670)
ExVal Low	(1,685)	(1,053)	(785)	(1,477)	(803)
CAGR Regr	(2,083)	(1,451)	(1,183)	(1,875)	(1,201)

TABLE 3 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-1998

1998

Demand case DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref High	**(1,181)**	**(548)**	**(281)**	**(1,060)**	**(298)**
Ref Base	**(1,373)**	**(741)**	**(473)**	**(1,252)**	**(491)**
EndYr High	**(1,482)**	**(849)**	**(582)**	**(1,361)**	**(599)**
Ref Low	**(1,542)**	**(910)**	**(642)**	**(1,421)**	**(660)**
EndYr Base	**(1,621)**	**(988)**	**(721)**	**(1,499)**	**(738)**
ExVal High	**(1,688)**	**(1,056)**	**(788)**	**(1,567)**	**(806)**
EndYr Low	**(1,729)**	**(1,096)**	**(829)**	**(1,608)**	**(846)**
Lin Regr	**(1,763)**	**(1,130)**	**(863)**	**(1,642)**	**(880)**
ExVal Base	**(1,881)**	**(1,248)**	**(981)**	**(1,759)**	**(998)**
ExVal Low	**(2,049)**	**(1,417)**	**(1,149)**	**(1,928)**	**(1,167)**
CAGR Regr	**(2,385)**	**(1,753)**	**(1,485)**	**(2,264)**	**(1,503)**

Bold signifies deficiency of at least 235 MW.

SOURCE: JH-RR-2(c) to 2(n)

TABLE 4

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000
1996

Demand case DSM	Low Supply	Base Supply	High Supply
Ref High	(660)	(28)	270
Ref Base	(724)	(92)	206
EndYr High	(922)	(290)	8
Ref Low	(935)	(303)	(5)
EndYr Base	(978)	(346)	(48)
ExVal High	(1,031)	(399)	(101)
EndYr Low	(1,061)	(429)	(131)
ExVal Base	(1,095)	(463)	(165)
ExVal Low	(1,306)	(674)	(376)
Lin Regr	(1,334)	(702)	(404)
CGR Regr	(1,780)	(1,148)	(850)

1997

Demand case DSM	Low Supply	Base Supply	High Supply
Ref High	(848)	(216)	82
Ref Base	(920)	(288)	10
Ref Low	(1,142)	(510)	(212)
EndYr High	(1,173)	(541)	(243)
EndYr Base	(1,244)	(612)	(314)
ExVal High	(1,345)	(713)	(415)
EndYr Low	(1,350)	(718)	(420)
ExVal Base	(1,417)	(785)	(487)
Lin Regr	(1,553)	(921)	(623)
ExVal Low	(1,639)	(1,007)	(709)
CGR Regr	(2,083)	(1,451)	(1,153)

TABLE 4 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

1998

Demand case DSM	Low Supply	Base Supply	High Supply
Ref High	(1,099)	(467)	(169)
Ref Base	(1,185)	(553)	(255)
EndYr High	(1,371)	(739)	(441)
Ref Low	(1,416)	(784)	(486)
EndYr Base	(1,457)	(825)	(527)
EndYr Low	(1,587)	(955)	(657)
ExVal High	(1,605)	(973)	(675)
ExVal Base	(1,691)	(1,059)	(761)
Lin Regr	(1,711)	(1,079)	(781)
ExVal Low	(1,922)	(1,290)	(992)
CGR Regr	(2,331)	(1,699)	(1,401)

1999

Demand case DSM	Low Supply	Base Supply	High Supply
Ref High	(1,368)	(736)	(390)
Ref Base	(1,489)	(857)	(511)
EndYr High	(1,580)	(948)	(602)
EndYr Base	(1,682)	(1,050)	(704)
Ref Low	(1,731)	(1,099)	(753)
EndYr Low	(1,837)	(1,205)	(859)
ExVal High	(1,855)	(1,223)	(877)
Lin Regr	(1,877)	(1,245)	(899)
ExVal Base	(1,976)	(1,344)	(998)
ExVal Low	(2,218)	(1,586)	(1,240)
CGR Regr	(2,591)	(1,959)	(1,613)

TABLE 4 (page 3)

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1996-2000

2000

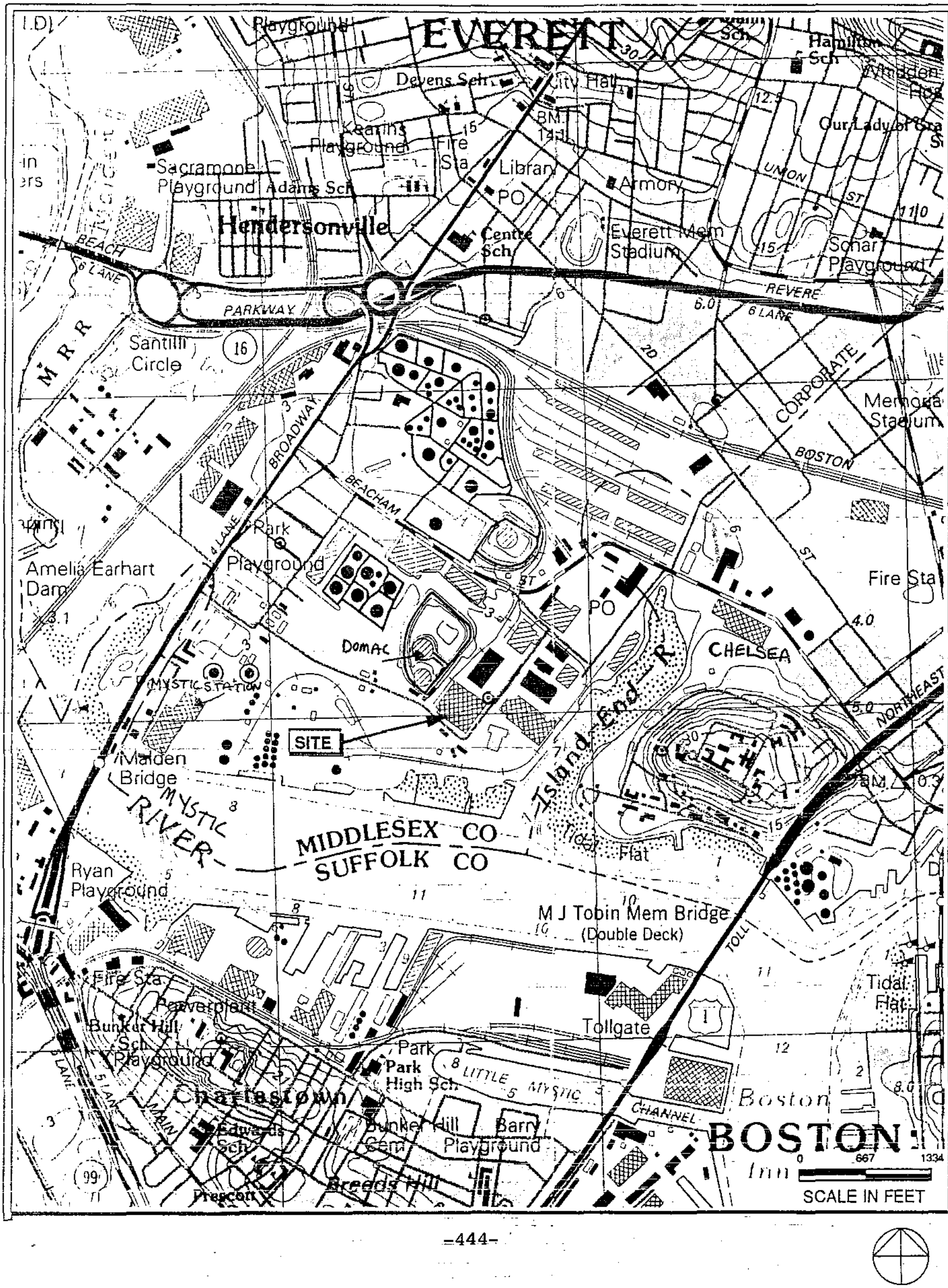
Demand case DSM	Low Supply	Base Supply	High Supply
Ref High	**(1,544)**	**(912)**	**(566)**
Ref Base	**(1,709)**	**(1,067)**	**(721)**
EndYr High	**(1,770)**	**(1,138)**	**(792)**
EndYr Base	**(1,889)**	**(1,257)**	**(911)**
Ref Low	**(1,954)**	**(1,322)**	**(976)**
Lin Regr	**(2,018)**	**(1,386)**	**(1,040)**
EndYr Low	**(2,070)**	**(1,438)**	**(1,092)**
ExVal High	**(2,092)**	**(1,460)**	**(1,114)**
ExVal Base	**(2,247)**	**(1,615)**	**(1,269)**
ExVal Low	**(2,502)**	**(1,870)**	**(1,524)**
CGR Regr	**(2,835)**	**(2,203)**	**(1,857)**

NOTES: Table 6 incorporates changes from Table 5 comparable to those incorporated in Table 2 from Table 1. **Bold** signifies deficiency of at least 235 MW.

SOURCES: Exhs. CPC-21, attachs. RLC-5, RLC-10, RLC-15; HO-RR-15, at 1; JH-1, at 31.

FIGURE I

SITE VICINITY MAP



Appeal as to matters of law from any final decision, order or ruling of the Siting Board 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 Board be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board 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).