Decision and Orders

Massachusetts Energy Facilities Siting Board

VOLUME 4

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Eastern Energy Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	))))))	EFSB 90-100R2

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
June 27, 1995

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I. INTRODUCTION

A. Procedural History

On January 29, 1990, Eastern Energy Corporation ("EEC" or "Company") filed with the Energy Facilities Siting Council ("Siting Council"),[1] a petition to construct a 300 megawatt ("MW"), coal-fired, circulating fluidized bed ("CFB") boiler cogeneration power plant on a 282 acre parcel of land in the Greater New Bedford Industrial Park in New Bedford, Massachusetts. The Siting Council docketed the petition as EFSC 90-100.[2] On July 23, 1991, the Hearing Officers issued the Tentative Decision in the proceeding. The Siting Council, by majority vote, adopted the Tentative Decision with some minor amendments at its August 2, 1991 meeting. EEC Decision, 22 DOMSC at 188.[3]

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1 Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), the Siting Council was merged with the Department of Public Utilities ("Department") 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 newly created Energy Facilities Siting Board ("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.

2 Jurisdiction over EEC's petition originally arose pursuant to G.L. c. 164, §§ 69H and 69I, which required electric companies to obtain Siting Board approval for construction of proposed facilities. Eastern Energy Corporation, 22 DOMSC 188, 200-202 (1991) ("EEC Decision"). Said jurisdiction is now codified in G.L. c. 164, §§ 69H and 69J.

3 In the EEC Decision, the Siting Council conditionally approved EEC's petition. The conditions imposed on EEC fell into two categories: viability and environmental issues. EEC was required to return to the Siting Council with supplemental filings that addressed each of these two categories. EEC Decision, 22 DOMSC at 315-316. Upon receipt of the supplemental filings, all parties to the initial proceeding were to be afforded the opportunity to address the supplemental filings and provide additional relevant information to supplement the record further. Id. at n.234.

On February 10, 1992, EEC filed its response to the environmental conditions contained in the EEC Decision ("Compliance Filing"), which was docketed as EFSC 90-100A. The Siting Council issued its Final Decision on the Compliance Filing on July 30, 1992. Eastern Energy Corporation, 25 DOMSC 296 (1992) ("EEC Compliance Decision"). No appeal was taken from the EEC Compliance Decision.

Timely appeals of the EEC Decision were filed with the Supreme Judicial Court ("Court") sitting in the County of Suffolk by the City of New Bedford ("CNB") and the Office of the Attorney General ("Attorney General"), both intervenors in the proceeding, pursuant to G.L. c. 164, § 69P and c. 25, § 5. The two appeals were reported by a single justice to the full Court and were consolidated as Civil Action S-5856.

On August 20, 1992, subsequent to the issuance of the EEC Compliance Decision, the Court issued its decision in the appeal. City of New Bedford v. Energy Facilities Siting Council (and a companion case), 413 Mass. 482 (1992) ("City of New Bedford"). In City of New Bedford, the Court concluded that the Siting Council exceeded its authority under G.L. c. 164, § 69H, and, as a result, the Court remanded the matter to the Siting Council "to compare alternative energy resources in its review of Eastern's application." Id. at 484. The Court also identified four "Other Issues which may Arise on Remand to the Council."[4] Id. at 489-490. In conclusion, the Court remanded the matter to the Siting Council "for reconsideration of Eastern's application consistent with this opinion." Id. at 490.

The proceedings on remand were docketed as EFSB 90-100R. The Siting Board conducted 18 days of evidentiary hearings in which the parties to the original proceeding were afforded the opportunity to address all issues identified by the Court in City of New Bedford. EEC presented two witnesses, the Attorney General presented four witnesses and

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4 The four issues were as follows: (1) "Because the statute mandates a 'necessary energy supply for the commonwealth' (emphasis added)," the Siting Council's specific finding that additional energy resources are needed for the New England area was "inadequate." City of New Bedford, 413 Mass. at 489. (2) "A finding that the new power would be produced at the lowest possible cost is necessary to conform to the council's legislative mandate." Id. (3) "Ensuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth' (emphasis added). G.L. c. 164, § 69H. In addition, the mandate requires a balancing of minimum environmental impact and lowest possible cost. It is inappropriate for the council to elevate to primary importance the economic benefits to be contributed to the Commonwealth over a balancing of these factors." Id. at 490. (4) "The final decision must do more than merely identify conflicting interests and contentions. See Hamilton v. Department of Pub. Utils., 346 Mass. 130, 137 (1963). The decision must be 'accompanied by a statement of reasons ... including determination of each issue of fact or law necessary to the decision'." Id.

the Greater New Bedford NO-COALition ("NO-COAL") presented six witnesses.[5] The Hearing Officer entered 312 exhibits into the record, EEC entered 327 exhibits into the record, the Attorney General entered 158 exhibits into the record and NO-COAL entered 28 exhibits into the record.[6]

On October 5, 1993, the Hearing Officer issued the Tentative Decision in the remand proceeding.[7] The Siting Board, by unanimous vote, adopted the Tentative Decision as amended at its October 22, 1993 meeting. Eastern Energy Corporation (on remand), 1 DOMSB 511 (1993) ("EEC (remand) Decision").[8]

Appeals of the EEC (remand) Decision were filed with the Court by the Attorney General, NO-COAL, and EEC, pursuant to G.L. c. 164, § 69P and c. 25, § 5. The Court subsequently dismissed EEC's appeal as untimely. Eastern Energy Corporation v. Energy Facilities Siting Board, 419 Mass. 151 (1994). The Attorney General's and NO-COAL's

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5 The initial proceedings entailed 14 days of hearings in which EEC sponsored 13 witnesses, the Attorney General sponsored two witnesses, the Massachusetts Department of Environmental Management sponsored one witness, and the CNB and NO-COAL sponsored the written testimony of one witness each.

6 These exhibits were in addition to the 872 exhibits entered into the record in EFSC 90-100 and EFSC 90-100A. The exhibits in those two proceedings were incorporated into and made a part of the record of the remand proceedings.

7 Although the Tentative Decision was dated October 4, 1993, from a practical perspective, it was not readily available to all parties until the following day.

8 The Siting Board found that there would be a need for 300 MW or more of additional energy resources for reliability purposes beginning in the year 1998 for Massachusetts and beginning in the year 2000 in New England. EEC (remand) Decision, 1 DOMSB at 465, 495. As it was unclear from the record whether the regional surplus would be available to meet the earlier need for power in the Commonwealth, the Siting Board found that the submission of (1) signed and approved power purchase agreements ("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 are the result of a competitive resource solicitation process beginning in 1993 or beyond and which are approved pursuant to G.L. c. 164, § 94A, would be sufficient evidence to establish that the proposed project would provide a necessary energy supply for the Commonwealth. Id. at 499.

appeals were consolidated as Civil Action S-6632. The Court issued its decision on the appeal on January 11, 1995. Attorney General v. Energy Facilities Siting Board (and a Companion Case), 419 Mass. 1003 (1995) ("Attorney General v. Siting Board").

B. The Appeal of the EEC Decision (on remand) and the Court's Decision in Attorney General v. Energy Facilities Siting Board

In their petitions for appeal, the Attorney General and NO-COAL raised several issues as causes of action. The first of these issues related to the Siting Board conditioning approval of the EEC project on the submission of signed and approved PPAs to demonstrate an earlier year of need. The Attorney General argued that, by conditioning approval on evidence that would not be submitted until some time in the future, the Siting Board precluded him from rebutting the evidence when it was submitted, in violation of his rights under G.L. c. 30A, §§ 10 & 11 (Attorney General Petition for Appeal at 12-14). NO-COAL interpreted the Siting Board's decision to condition approval on the submission of signed and approved PPAs as a failure to find a need for the proposed project (NO-COAL Petition for Appeal at 2, 7, 8). With regard to future need, NO-COAL also speculated that future electrical loads might in fact decrease as additional energy efficient appliances are installed and that "improvements in renewable resource technologies could reduce the costs for alternative methods of electrical generation which could also result in reduced environmental harm" (id.).

As a second issue, both the Attorney General and NO-COAL argued that the list of alternatives contained in G.L. c. 164, § 69J includes the alternative of conservation (Attorney General Petition for Appeal at 14-17) or conservation and load management ("C&LM") (NO-COAL Petition for Appeal at 5-7) and faulted the Siting Board for not evaluating these as alternatives to the proposed project.[9] As a third issue, both the Attorney General and

[9] In paragraph #63 of the Attorney General's Petition for Appeal the Attorney General argued that "In the context of G.L. c. 164, § 69J, and the entire statutory scheme, the term 'no additional electrical power' means conservation."

(continued...)

NO-COAL argued that the Siting Board's balancing of cost and environmental impacts, a requirement that the Court in City of New Bedford specifically acknowledged to be a proper function of the agency, was not properly conducted.[10]

As noted above, the Court issued its decision in Attorney General v. Siting Board on January 11, 1995.[11] The Court remanded the case to the single justice with instructions that the Siting Board decision conditionally approving the siting of the EEC facility be vacated, and directed that "[a]ny question concerning a reopening of the [Siting B]oard's hearings is left to the discretion of the [Siting B]oard." Attorney General v. Siting Board, 419 Mass. at 1005.

Addressing the Siting Board's conditional approval of the proposed EEC project, the Court stated that the Siting Board had not explained how the approval of PPAs by the Department, which may show need for an individual utility, implies a need for the Commonwealth. Id. at 1004-1005. The Court noted that it had not received a reasoned

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[9](...continued)
NO-COAL cited the language of G.L. c. 164, § 69I and asserted that the language "and no additional electrical power or gas; a reduction of requirements through load management" means that conservation and load management must be considered as an alternative (NO-COAL Petition for Appeal at 5). The Siting Board notes that Section 69I does not apply to the present proceeding, but that the cited language is identical in Section 69J, the section that does apply.

[10] In the Eastern (remand) Decision, the Siting Board's analysis established that EEC's proposed facility was clearly superior to five alternatives. 1 DOMSB at 396. In a comparison of the proposed facility with the remaining alternative, a natural gas-fired, combined-cycle power plant, the proposed facility had a significant cost advantage, but the natural gas-fired alternative was preferable with respect to environmental impacts, with a significant advantage only in the area of air impacts. Id. at 386-390. The Siting Board then balanced the environmental impacts and costs of the proposed facility and the natural gas alternative as directed by the Court. City of New Bedford, 413 Mass. at 486.

[11] On the same day that it issued its decision in Attorney General v. Siting Board, the Court issued its decision in Point of Pines Beach Association, Inc. v. Energy Facilities Siting Board, 419 Mass. 281 (1995) ("Point of Pines"). The Court relied on its discussion of the issues in Point of Pines in its disposition of the Siting Board decision at issue in Attorney General v. Siting Board.

explanation of the inferability of Commonwealth need from utility need in either this case, arguments before the Court concerning this case, or in previously cited Siting Board decisions. Point of Pines, 419 Mass. at 284-285. Further, the Court noted that the Siting Board may not abdicate its independent responsibility to ensure that projects are necessary by relying solely on conclusions of the Department and that the Siting Board must make an independent finding of Commonwealth need before approving the construction of a new facility. Id. at 286; Attorney General v. Siting Board, 419 Mass. at 1004-1005.

The Siting Board will comply with the Court's directive relative to making an independent finding regarding the need for EEC's proposed project in Section II.B, below. Before doing so, however, the Siting Board notes that the Court's decision in Attorney General v. Siting Board did not address several other issues which were raised on appeal. Our analysis in this decision will rely in part on portions of the EEC (remand) Decision which were not addressed by the Court. Therefore, we find it necessary to also address herein the misunderstandings or misinterpretations of the parties reflected in those other issues which were raised on appeal, in order to clarify the basis for, and the subsidiary findings of, this decision and the EEC (remand) Decision.

As to the first issue raised on appeal, i.e., use of signed and approved PPAs as evidence of need earlier than the year 2000, the Siting Board acknowledges that it did not properly justify their use in the EEC (remand) Decision. Further, the Siting Board will neither place any reliance on such PPAs as evidence of need in this decision, nor place any condition on EEC that requires the submission of PPAs for such purpose in the future. Accordingly, the Attorney General's argument with regard to this issue is moot.

In regard to NO-COAL's assertion as to the Siting Board's failure to find a need for the proposed project, the Siting Board will address this in Sections II.B.2 and II.B.3, below. As to NO-COAL's speculation that future need may decrease, the Siting Board notes that the record evidence provides no support for such speculation. Further, the Siting Board examined both of the contingencies identified by NO-COAL in its Petition for Appeal during hearings and in the need analysis projections of demand-side management ("DSM") that were used in the EEC (remand) Decision. Based on that analysis, the Siting Board found that, contrary to NO-COAL's assertions, future need would increase.

With regard to the second issue raised on appeal regarding conservation, or conservation and load management, in essence, both the Attorney General and NO-COAL urged the Siting Board to ignore the plain language of its statute and Court decisions that indicate the proper tools for use in statutory interpretation.[12] In considering whether conservation or conservation and load management should be analyzed as alternatives to a proposed project, "[t]he starting point of our analysis is the language of the statute, 'the principal source of insight into Legislative purpose.' Commonwealth v. Lightfoot, 391 Mass. 718, 720 (1984)." City of New Bedford, 413 Mass. at 484, citing, Simon v. State Examiners of Electricians, 395 Mass. 238, 242 (1985).

Specifically, G.L. c. 164, § 69J's requirements include that:

> [a] petition to construct a facility shall include ... the following information: a description of actions planned to be taken by the applicant to meet future needs or requirements, including, but not limited to ... a description of alternatives to planned action such as ... no additional electrical power or gas; a reduction of requirements through load management ... (emphasis added).

Additional requirements of Section 69J include that:

> [t]he [Siting B]oard shall ... approve a petition to construct a facility ... if it determines that it meets the following requirements: ... projections of the demand for electric power, or gas requirements and of the capacities for existing and proposed facilities are based on substantially accurate historical

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12 The Court has held that, in construing a statute, common words and phrases employed in the statute are to be accorded their usual meaning. Commissioner of Corp. & Tax v. Chilton Club, 318 Mass. 285, 288-289 (1945), citing, Fluet v. McCabe, 299 Mass. 173, Hinckley v. Retirement Board of Gloucester, 316 Mass. 496, and Killiam v. March, 316, Mass. 646. In addition, statutory language, when clear and unambiguous, must be given its ordinary meaning. Bronstein v. Prudential Ins. Co. of America, 390 Mass. 701, 704 (1984); Hashimi v. Kalil, 388 Mass. 607, 610 (1983). Further, none of the words of a statute is to be disregarded, for they are the main source for the ascertainment of the legislative purpose. Commissioner of Corp. & Tax v. Chilton Club, 318 Mass 285, 288 (1985); Nichols v. Commissioner of Corporations & Taxation, 314 Mass. 285 (1943). And, "no word in a statute is to be treated as superfluous, unless no other possible course is open." Commonwealth v. McMenimon, 295 Mass. 467, 469 (1936).

> information and reasonable statistical projection methods and include an adequate consideration of conservation and load management ... (emphasis added).

Based on the ordinary meaning of the words of Section 69J, the Legislature has directed the Siting Board to include consideration of "conservation and load management" in its projections of the demand for electric power. Had the Legislature meant "conservation" to be included as an alternative, the Siting Board presumes the Legislature would have so stated. To assume that the Legislature intended the term "no additional electrical power"[13] to mean the same as "conservation" when it had used this latter term elsewhere in the same statute, would result in the Siting Board ignoring the plain meaning of the words that were used and disregarding other words in the statute. Therefore, the Siting Board declines to accept the argument of the Attorney General that would have the Siting Board ignore the intent of the Legislature as ascertained by the Legislature's choice of words.

Similarly, NO-COAL would have the Siting Board ignore that (1) the language they cite does not include the word "conservation," and (2) the term "load management" as used in the language cited modifies the phrase "description of actions planned to be taken by the applicant to meet future needs and requirements" and is not included in the clause that lists "a description of alternatives to such action."[14] G.L. c. 164, § 69J. In City of New Bedford, the Court faulted the Siting Council for failing to undertake a comparison of alternatives, a requirement that was clear from the language of the statute and identified by the Court in that decision. 413 Mass. at 487-488. Where as here, the language of the statute is clear, and the rules of statutory interpretation prevent us from ignoring the plain

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[13] The Siting Board more fully addressed the meaning of the words "no additional electrical power" in the context of its statute in the Eastern (remand) Decision, 1 DOMSB at 286-288.

[14] The Siting Board is cognizant of the fact that the terms "conservation" and "load management" are often used interchangeably or combined, as in "conservation and load management," although their meanings are distinguishable. In regard to the use of these terms in G. L. c. 164, it is important to acknowledge that the Legislature used the terms in distinctly different situations, a point that is not lost by the Siting Board in reviewing the records in proceedings before it. See, EEC (remand) Decision, 1 DOMSB at n.94 for definitions of those terms.

language or treating it as superfluous, the Siting Board has refused to adopt the arguments of the Attorney General and NO-COAL to do otherwise.[15,16]

The third issue raised on appeal by the Attorney General and NO-COAL addresses the Siting Board's balancing of environmental impacts and cost. Specifically, the Court stated that the mandate of the siting statute requires the Siting Board to "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. Further, this "statutory balance involves weighing minimum environmental impact and cost." Id. at 486. Neither the statute nor the Court indicated how such a balancing should be accomplished.[17]

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15 In addition, the Siting Board's interpretation of the language of its statute is consistent with an attempt to read the statute in a manner that will make sense of the legislative enactment. The Siting Board requires developers to "include an adequate consideration of [C&LM]" in its projections of the demand for power by requiring the inclusion of all cost-effective C&LM measures, based on reasonable statistical projections. Projections of future demand are then reduced by the identified amount that can be attributed to such C&LM to establish the level of future need. As all cost-effective C&LM has been assumed, no additional cost-effective C&LM measures would be available as an alternative to the planned action.

16 The Siting Board also notes that, as the Court indicated in City of New Bedford, prior to the review of EEC's proposed facility in the EEC Decision, the Siting Council "had required a nonutility applicant to establish that its proposed project was superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need for energy. This past practice comports with the [Siting C]ouncil's statutory mandate." 413 Mass. at 482. These past comparisons, for the reasons cited above, did not include a comparison of conservation as an alternative. Rather, conservation was analyzed in these earlier cases as required by the statute by adequately considering C&LM in the projections of the demand for electric power. The Siting Board can find no basis for abandoning a practice that is consistent with the language of its statute and that has been specifically acknowledged by the Court to comport with the statutory mandate.

17 Although both the Attorney General and NO-COAL fault the balancing approach adopted by the Siting Board in the EEC (remand) Decision in response to the Court's directive, neither party has indicated an alternative approach that would be responsive to the Court's directive or justified under the statute.

The Court did acknowledge that the Siting Board could site a project with greater environmental impacts if it explicitly stated that it was doing so on the basis of a determination that other factors outweighed those environmental impacts. Id. at 490. The Siting Board did exactly that in the EEC (Remand) Decision. 1 DOMSB at 396. Further, the Siting Board looked to the language of its statute for guidance in balancing the environmental impacts and cost. See Id., 1 DOMSB at 390-396, 397.

Since one predominant concern of the statute is the provision of a necessary energy supply for the Commonwealth, and necessary energy might not be available to provide if the energy supply lacked reliability, the Siting Board found it necessary to weigh the relative value of the costs and environmental benefits of the proposed project and the natural gas alternative (see n.10, above) in light of their respective contributions to the reliability of the Commonwealth's energy supply.[18] Id., 1 DOMSB at 391, 392. That reliability lies, in part, in maintaining an energy supply which prevents overdependence on any one fuel.[19] Id., 1 DOMSB at 392. As record evidence supported a finding that reliance on natural gas was increasing at a rate faster than reliance on coal, the Siting Board found that the proposed project (which would be fired with coal) would provide system reliability advantages over the natural gas-fired alternative. Id., 1 DOMSB at 394-396. Thus, the Siting Board took the "mandate of the siting statute" (as identified by the Court on page 485 of City of New Bedford) and "balance[d the] environmental harm that would be caused by [the proposed] new power plant against the other statutory objectives -- providing a necessary energy supply at the lowest possible cost." Upon doing so, the Siting Board determined that it was appropriate to give more weight to the specific cost benefits of the proposed facility in comparison to the air quality benefits of the natural gas-fired alternative. Id. at 396. This was so because the proposed facility would increase the system reliability of the

18 As stated in note 16, above, reliability was one aspect of the Siting Council's alternatives analysis in cases prior to the EEC Decision, which the Court noted comports with the statutory mandate.

19 The Siting Board also noted that other issues relative to the reliability of the electric energy supply as a whole include transmission and distribution system reliability. EEC (remand) Decision, 1 DOMSB at n.242.

Commonwealth's energy supply, and would, therefore, help to provide a necessary energy supply.

The Attorney General apparently misunderstood this finding, construing it as a finding that coal as a fuel for the Commonwealth's energy supply would be more reliable than natural gas or less subject to fuel disruptions (Attorney General Petition for Appeal at 18-20).[20] He then argued that the Siting Board had failed to support this finding with substantial record evidence or with adequate subsidiary findings (id. at 17). The Siting Board, however, did not make such a finding, as it had no reason to do so. Accordingly, the Attorney General's argument that the finding is not supported is misplaced.[21]

Rather, the Siting Board found that the increasing reliance on natural gas as a part of the fuel mix for the Commonwealth's energy supply when compared to the reliance on coal as a part of the fuel mix, which was at best remaining static and likely to be decreasing, meant that the fuel mix of the Commonwealth's energy supply would be more diverse, and hence more reliable, with the addition of a coal-fired project as compared to the addition of another natural gas-fired project. EEC (remand) Decision, 1 DOMSB at 394-395. Accordingly, in balancing the relative value of environmental impacts and cost of the proposed coal-fired project and those of a natural gas-fired alternative, the Siting Board provided a specific determination that, as the Court explicitly allowed in City of New Bedford, 413 Mass. at 490, it was siting a project with greater environmental impacts on the basis of a determination that other factors outweighed those environmental impacts. Id., 1

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20 In fact, the Siting Board found the percentage of coal and natural gas currently present in the Commonwealth's and region's fuel mix to be relatively comparable. EEC (remand) Decision, 1 DOMSB at 393. Further, the Siting Board explicitly recognized "that there is still a need for additional gas-fired generation for system-wide reliability purposes." Id., 1 DOMSB at 395.

21 Alternatively, the Attorney General's claim might be construed as an argument that the Siting Board would have to make such a finding in order to find that an advantage existed for the proposed project as compared to a natural gas-fired alternative. However, such a finding is not necessary to support the Siting Board's conclusion that the proposed project, as an incremental addition to the Commonwealth's energy supply, would improve the reliability of that energy supply.

DOMSB at 396. The Siting Board based this finding on substantial record evidence as set forth in the EEC (remand) Decision, 1 DOMSB at 390-396, and adequate subsidiary findings as set forth in those same pages and summarized on page 397 of that same decision.[22]

C. Post-Appeal Procedural History

As noted above, the Court left to the discretion of the Siting Board whether to reopen hearings. Attorney General v. Siting Board, 419 Mass at 1005. Thus, the Siting Board must first determine whether it is necessary to reopen hearings to respond to the Court's directive. In order to make such a determination, the Siting Board must review the existing record and determine whether the evidence contained therein is sufficient for a response to the Court, and if it is sufficient, whether the evidence remains valid. Finally, if the record evidence is sufficient and valid, the Siting Board must determine whether other factors might require the Siting Board to exercise its discretion and reopen hearings.

The Siting Board notes that it has before it both EEC's pending petition and an extensive evidentiary record that has been developed over more than four years by all parties to the proceeding. In order to make the above-noted determinations and move the proceeding toward closure, the Hearing Officer issued a memorandum on February 2, 1995 ("Memorandum") that provided all parties to the proceeding with an opportunity to address the issue of the reopening of hearings. In it, the Hearing Officer asked parties "to address the continued validity/sufficiency of the [existing] record evidence for the purpose of responding to the Court's directive" in Attorney General v. Siting Board (Memorandum at 2). The Memorandum established a procedure that provided all parties with the opportunity to "make an Offer of Proof, as to specific additional information which should be included in the record to enable the Siting Board to decide those issues relevant to the Court's directive"

22 NO-COAL raised three other issues in its Petition for Appeal but failed to pursue them on brief before the Court. NO-COAL argued that the Siting Board: (1) erroneously found the proposed project to be lowest possible cost (NO-COAL Petition for Appeal at 10-11); (2) failed to apply Department and [Siting] Board standards in a consistent manner (id. at 13-14); and (3) denied NO-COAL due process by the systematic exclusion of evidence (id. at 14-16).

(id.). The information to be submitted by the parties was to indicate the nature of the evidence (e.g., testamentary, documentary, etc.) that would constitute the Offer of Proof, the expectations of the movant as to what issues would be addressed and what would be demonstrated if such evidence were introduced, and the reasons why such evidence was not available at the time of the earlier development of the administrative record in the proceeding (id.). Further, all parties were provided an opportunity to submit a rebuttal to any Offer of Proof that was submitted (id.).[23]

The following four Offers of Proof were submitted: (1) February 21, 1995 Memorandum of the Greater New Bedford NO-COALition ("NO-COAL Offer of Proof"); (2) February 23, 1995 Letter from Robert Ladino ("R. Ladino Offer of Proof"); (3) February 24, 1995 Offer of Proof of the Attorney General ("Attorney General Offer of Proof"); and (4) February 24, 1995 Filing of Eastern Energy Corporation in Response to the Hearing Officer's Memorandum ("EEC Offer of Proof"). In addition, the following four rebuttals were submitted: (1) March 6, 1995 NO-Coal's Motion in Opposition ("NO-COAL Rebuttal"); (2) March 6, 1995 Letter from Robert Ladino in Response to EEC's February 24th Filing ("R. Ladino Rebuttal"); (3) March 6, 1995 Rebuttal of the Attorney General to EEC's Filing ("Attorney General Rebuttal"); and (4) March 6, 1995 Filing of EEC in Response to Hearing Officer's Memorandum ("EEC Rebuttal").

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23 The Memorandum did not require the parties to submit additional record evidence (Hearing Officer Procedural Order of February 16, 1995) ("Procedural Order"). Rather, it asked the parties to indicate whether the existing record remained valid and sufficient to enable the Siting Board to respond to the Court's directive (Memorandum at 2). Further, if any party believed the record was not valid or sufficient, he was directed to identify specifically the additional information which the Board should consider, explain what that information would demonstrate, and explain why it was not previously available (id.). The Hearing Officer requested this information to assist him in determining whether it was necessary to reopen hearings to take additional evidence in order to respond to the Court's concerns. However, parties were under no obligation to provide the Hearing Officer with such assistance (Procedural Order at 2). The submissions that were made addressed the Hearing Officer's request to varying degrees and in varying ways, but for purposes of further discussion, all submissions will be referenced as Offers of Proof or Rebuttals as envisioned by the Memorandum.

1. The Parties' Offers of Proof

The Attorney General asserted that the record should not be reopened, and noted that the Court confirmed the Siting Board's finding that it was unable to find Massachusetts need before the year 2000 (Attorney General Offer of Proof at 2). Therefore, he concluded that the petition to construct the proposed facility should be denied (id.). Further, the Attorney General argued that, if the Siting Board did not deny the petition based on the existing record, it must reopen the record to address new evidence (id. at 3, 8).[24]

The Attorney General then outlined information that should be evaluated if the record is reopened. In regard to the issue of need, the Attorney General stated that the latest New England Power Pool Forecast Reports of Capacity, Energy, Loads and Transmission ("CELT Reports") need projections should be analyzed as they demonstrate reduced need (id. at 3). Further, he stated that he would analyze issues of economic stagnation and growth, substantial recent developments in the use of renewables, and the potential effects of the electric industry restructuring efforts (id. at 4).[25] The Attorney General also stated that, since the close of the record, evaluations of DSM programs have progressed significantly and utilities have incentives, and are likely, to implement additional DSM programs (id. at 5). Further, he argued that DSM would also increase with the upgrades of building codes as a result of Federal legislation from 1987, 1988 and 1992 and that for this reason and others, utilities have under-forecasted savings from DSM (id. at 5-6). The Attorney General asserted that, if appropriate corrections were made for this under-forecasting of DSM, there would be a further reduction in need for new generation (id.).

24 Specifically, the Attorney General stated that if the Siting Board "refuse[s] to deny [EEC's] Petition on the existing record, the [Siting] Board has no choice but to reopen the record and hold new hearings. The [Siting] Board cannot, consistent with the Court's opinion and the siting statute, keep the record closed and then approve the project by recasting the existing evidence" (Attorney General Offer of Proof at 3).

25 The Attorney General maintained that "[t]he scope of the presentation is likely to be as extensive as, or more extensive than, the prior need evaluations performed by the Attorney General in this case" (Attorney General Offer of Proof at 5).

The Attorney General also stated that he would demonstrate that natural gas prices are projected to decrease and concluded that, as a result, the natural gas/oil-fired combined cycle and natural gas-fired alternatives would be less costly or of equal cost to the proposed plant (id. at 7). The Attorney General asserted, therefore, that he would demonstrate that there is neither Massachusetts nor regional need for the proposed facility within the reasonable planning horizon (id. at 5).

NO-COAL and Mr. Ladino argued that the record should not be reopened, and that a new final decision denying EEC's petition would be warranted (NO-COAL Offer of Proof; R. Ladino Offer of Proof at 1-2).[26] Neither NO-COAL nor Mr. Ladino identified any issues that would need to be addressed in response to the Court's directive, but NO-COAL reserved its right to submit a rebuttal to other Offers of Proof and Mr. Ladino reserved his right to participate in future proceedings (id.).

EEC asserted that the record should not be re-opened and that the existing record is sufficient to support a decision to approve the proposed facility (EEC Offer of Proof at 1). EEC stated that the Court's decision found fault only with the Siting Board's new "market-based test" of need, which required the submission of signed and approved PPAs (id. at 3). The Company argued that the Siting Board has already made the mandated independent finding of need required to approve the facility, in as much as the Siting Board has determined that EEC will provide a necessary energy supply for the Commonwealth beginning in the year 2000 (id. at 4, 5).

The Company stated that, due to delays in the construction schedule for the proposed facility arising from litigation, the in-service date of the project would be pushed back until the 1999-2000 time frame (id. at 6). EEC cited record evidence that indicated that it would need 47 months for further permitting and construction following financial closing, which would not occur until some time after Siting Board approval (id. at 6, citing,

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26 Mr. Ladino's submission was premised, in part, on his belief that the Court interpreted the siting statute as requiring "that the demonstrated need must be established before the size of [a proposed] plant can be determined" (R. Ladino Offer of Proof at 3). Mr. Ladino noted that, in the current record, plant size was established before being justified by statistical forecasts (id.).

Exh. HO-PV-1). As Siting Board approval could occur no earlier than the summer of 1995, the earliest possible on-line date for EEC's proposed project would be in the summer of 1999, assuming financial closing was contemporaneous with Siting Board approval, a logistically unlikely result (id. at 6-7). EEC stated that the Siting Board has found that it is appropriate to consider the need for a project in the first few years of operation, and that at the worst, the EEC project, if built in 1999, would be needed by its second year of operation (id. at 8).

EEC argued that the Siting Board could also make a finding of need for at least 300 MW of additional capacity before the year 2000 based on the current record and a reconsideration of the October 4, 1993 Tentative Decision (id.). The Company asserted that overwhelming evidence supported the staff conclusion in the Tentative Decision that the proposed facility would be needed in the Commonwealth beginning in 1998 even after applying identified regional surpluses in that year (id. at 9-11). Similar analyses showed a continued need in the year 1999 (id.). The Company further argued that it would be appropriate to adopt staff's analyses, since the language that discussed them was deleted from the Final Decision as a result of the amendment that contained the condition relative to PPAs that was rejected by the Court in Attorney General v. Siting Board (id. at 9).

Finally, EEC asserted that the submission of new evidence would only reinforce the previous findings of the Siting Board and would accelerate the year of need (id. at 13). In support of its assertion, the Company provided information in the form of an affidavit prepared by Robert Graham, of La Capra Associates ("Graham affidavit") that it would submit as evidence if hearings were reopened (id., Attachment B). The Graham affidavit purports to show an earlier year of need based on analyses of recent CELT Reports (id.).

2. The Parties' Rebuttals

In response to EEC's Offer of Proof, the Attorney General acknowledged that the Siting Board has the authority not to reopen the record in this proceeding (Attorney General Rebuttal at 1). However, he challenged EEC's assertion that the Siting Board could approve EEC's petition without reopening the record, by arguing that to do so would be legal error (id.). The Attorney General further noted in agreement with EEC, that the Siting Board had found that EEC's proposed project would be needed beginning in the year 2000 by citing to the Final Decision wherein the Siting Board found that the record demonstrated a need for at least 300 MW in the Commonwealth for the years 2000 and beyond (id. at 2, citing, EEC (remand) Decision, 1 DOMSB at 498).

The Attorney General also argued that if the Siting Board accepts EEC's assertion that the in-service date of the proposed facility has been delayed as the result of litigation, then EEC should be required to reevaluate two other areas of the decision, the alternative technologies comparison and the balancing of environmental impacts and costs, based on the new in-service date (id. at 6). He asserted that the evidence used in the EEC (remand) Decision was geared to evaluate a plant designed to come on-line in 1997 (id.). He further asserted that as technology changes, alternatives to the proposed project, such as renewables and cleaner generations of fossil fuel plants, are becoming more readily available (id.).[27] The Attorney General argued, therefore, that "[i]f the [Siting] Board accepts any new evidence on need as of the year 2000, the [Siting] Board should not effectively freeze in time the required alternatives analysis and environmental impacts/costs balancing" (id. at 7).

The Attorney General also challenged EEC's argument that the Siting Board staff analyses in the Tentative Decision support a finding of need before the year 2000. Specifically, the Attorney General stated that the Siting Board had rejected the Tentative Decision's reasoning concerning meeting Massachusetts need out of the regional surplus because no record on that point had been developed. He therefore concluded that the Siting Board could not now make any different finding regarding Massachusetts' first year of need (id. at 3). The Attorney General noted that the "Final Decision contained over one hundred pages of need analysis which culminated with the finding" that the record did not support a finding of need before the year 2000 (id. at 4). In addition, he noted that the Court did not disturb the Siting Board's factual finding that no record was developed on the surplus issue,

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27 For example, the Attorney General cited the testimony of his witness during the remand proceedings that a coal gasification plant would likely reach comparable availability to the proposed project by the mid- to late-1990s and would become "mature" by 2000 (Attorney General Rebuttal at 6).

and that the existing record does not support a conclusion that the forecasted regional surplus in 1998 and 1999 would not be available to the Commonwealth in those years (id.).

Finally, the Attorney General argued that the Siting Board may not selectively consider new information concerning need, such as that submitted by EEC as an affidavit to its Offer of Proof (id. at 4). In addition, he took issue with many of the conclusions and methods contained in EEC's affidavit (id. at 5 & n.5). The Attorney General argued that a new need analysis, such as that submitted in the EEC Offer of Proof, should be considered only in a reopened proceeding, where the intervenors would be allowed to rebut the evidence submitted (id. at 5). The Attorney General concluded that EEC's submission "cries out for a full re-evaluation of need" (id. at 6).

NO-COAL also disagreed with EEC's assertion that the existing record supports an approval of the proposed facility, and cited the release of more updated CELT reports as a premise for its disagreement (NO-COAL Rebuttal). NO-COAL asserted that the affidavit submitted by EEC with its Offer of Proof is inadmissible if the record is not reopened, and argued that EEC should not fear reopening the record if, as EEC has claimed, its evidence would corroborate the reliability of the existing record (id.).[28]

Mr. Ladino took issue both with the scope of our present review in EFSB 90-100R2 and with EEC's statement that the Court found fault only with the new "market-based" test of need, noting that the Court found that the decision lacked an independent finding of need (R. Ladino Rebuttal at 2). In regard to EEC's argument that the staff's analyses in the Tentative Decision demonstrated a need before the year 2000, Mr. Ladino asserted that the Tentative Decision was inadequate when it was presented and that it remains so (id. at 4). Mr. Ladino urged that EEC's affidavit be rejected as it did not constitute the independent finding of need required by the Court, and based on his analysis, the affidavit was inaccurate and biased (id. at 5-7). Finally, Mr. Ladino stated that the Siting Board's only option, based on the existing record, would be to deny the petition (id. at 8).

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28 NO-COAL's Rebuttal also took issue with various statements made by the Hearing Officer and the Siting Board. As the purpose of the rebuttal submissions was to allow responses to the parties' Offers of Proof, these additional non-rebuttal issues will not be addressed here.

EEC asserted that the Attorney General's Offer of Proof failed to provide the specificity or sufficiency necessary for an Offer of Proof in an administrative setting or to meet the essential criteria established by the Hearing Officer in his Memorandum (EEC Rebuttal at 2-3). The Company indicated that, through the use of the Offer of Proof, the Siting Board had given the parties the opportunity to identify specific, concrete evidence of the type on which the Siting Board could rely in deciding the case if it decided to re-open the record (id. at 3).[29] EEC stated that the Attorney General's Offer of Proof "falls far short of this standard" as it only identified the issues the Attorney General would explore if the record were reopened (id. at 3-4). EEC urged the rejection of the Attorney General's Offer of Proof as inadequate support for the Attorney General's assertions regarding EEC's petition (id. at 3, 5).

Nevertheless, in response to issues raised by the Attorney General, EEC responded that the most recent data on load forecasts and available energy resources, including the initial 1994 CELT forecast, support a finding of a significantly greater need than that found in the EEC (remand) Decision (id. at 6). Specifically, EEC refuted the Attorney General's claims that recent economic projections and DSM estimates would tend to reduce forecasted loads, providing a second affidavit from Mr. Graham, which concluded that those factors would increase load growth and require the addition of new capacity before the year 2000 (id.). EEC argued that the Attorney General's statement that he would "analyze issues of economic stagnation," does not constitute an Offer of Proof and noted that Mr. Graham's statistics show that the economy has improved since the close of the record, rather than stagnating as the Attorney General claimed (id. at 6-7).

In regard to regulatory restructuring and DSM, the Company noted that the Attorney General offered no additional projections of DSM and no specific evidence as to the effects

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29 EEC asserted that, due to the magnitude of the delay in resolving this case, the record should be re-opened under only the most extraordinary of circumstances where compelling new evidence has been offered (EEC Rebuttal at 3). EEC noted that G.L. c. 164, § 69J envisions a twelve-month schedule for Siting Board review of petitions thereunder (id.). EEC further noted that more than five years has passed since its initial petition was filed and, to date, no final resolution of that petition has been reached (id.).

of restructuring on the need for electricity[30] (id. at 7-8). Further, EEC argued that the Attorney General offered no proof that the DSM projections used in the EEC (remand) Decision are inaccurate, and concluded, therefore, that there was no reason to revisit the issue (id. at 8).

Finally, with respect to the Attorney General's assertions relative to gas prices, EEC acknowledged the volatility of gas and oil prices in the short-run. However, EEC noted that the Siting Board had reviewed several long-run forecasts of gas and oil prices, which have not been challenged by the Attorney General, and asserted that the Siting Board must focus on these in the comparison of alternative facilities (id. at 10). Thus, the Attorney General's assertion that the natural gas-fired alternative and the gas/oil-fueled alternative would be less costly than EEC's proposed project if compared on the basis of these lower fuel costs ignores the true fuel costs on which a comparison of energy facilities should be made (id. at 10-11). EEC noted that, even assuming lower gas prices, the Attorney General did not assert that the natural gas-fired alternative would be equal or less in cost than the proposed project, and he provided no documentation for his assertion that the gas/oil alternative would be so (id. at 9, 10). In addition, EEC argued that the Attorney General ignored other cost factors, such as lower interest rates, which would favor EEC's proposed project if a complete new analysis were required (id. at 10-11). EEC concluded that the comprehensive analysis of alternatives conducted by the Siting Board in the EEC (remand) Decision was based on voluminous record evidence and that the Attorney General's "conclusory and unsupported assertions are simply not a sufficient basis to revisit the [Siting] Board's findings on this issue" (id. at 11).

3. Analysis

An analysis of the issues and arguments provided in the various Offers of Proof and Rebuttals must commence with a review of the Court's decision in Attorney General v. Siting Board, specifically with regard to the scope of the Court's directive to the Siting Board. In

[30] EEC noted that since the scope and timing of any future restructuring is currently unknown, it is "hardly possible to come to any rational conclusions about" it at this time (EEC Rebuttal at 7).

that decision, the Court noted that, in response to its remand in City of New Bedford, the Siting Board "conducted further hearings and, after examining numerous capacity and demand forecasts, concluded that 'based on the record, the [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.'" 419 Mass. at 1004. The Court continued by noting that "[b]ecause the board in this case failed to make an independent finding that the proposed project is needed to provide a necessary energy supply for the Commonwealth, and because standing alone, signed and approved power purchase agreements do not warrant an inference of need, we conclude that the board's decision must be vacated." Id. at 1005. The Court then left to the Siting Board's discretion "whether to reopen hearings on this matter." Id. Thus, the Court vacated the Siting Board's decision due to the lack of a single finding and the improper or unexplained substitution of a proxy for that finding. Accordingly, the Siting Board finds that the scope of the Court's directive in Attorney General v. Siting Board is very specific and is limited to the requirement that the Siting Board make an independent finding of need and not rely on signed and approved PPAs to take the place of such a finding.

The Court did not indicate that this necessary finding could not be made on the existing record. Rather, the Court acknowledged that the Siting Board has reviewed pertinent evidence, i.e., numerous capacity and demand forecasts.[31] Further the Court authorized the Siting Board to use its discretion in determining whether this record needed to be reopened. Therefore, the Siting Board finds that it must determine whether the existing record evidence on which its findings of need are based remains valid and sufficient. First, however, in light of various arguments raised by the parties that would limit the Siting Board's options in this proceeding, the Siting Board must address what is meant by the term "discretion" as used by the Court.

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[31] In fact, this was the second time that need had been analyzed, as the Siting Council, in the EEC Decision, had also undertaken a complete regional need analysis in which capacity and demand forecasts were investigated.

A look at pertinent case law establishes that when discretion is exercised, it cannot lead to arbitrary action, but it also cannot lead to actions based on decisions made in a vacuum. Discretion implies flexibility and requires judgment based on consideration of all facts surrounding a situation. The Court has held that the term discretion when used in a statute denotes "freedom to act according to honest judgment." Paquette v. Fall River, 278 Mass. 172, 174 (1932); Corrigan v. School Committee of New Bedford, 250 Mass. 334, 339 (1924). In Paquette, the Court noted a United States Supreme Court decision that stated "The term *discretion* implies the absence of a hard-and-fast rule. The establishment of a clearly defined rule of action would be the end of *discretion*, and yet discretion should not be a word for arbitrary will or inconsiderate action. 'Discretion means a decision of what is just and proper in the circumstances.'" 278 Mass. at 174, citing, The Styria v. Morgan, 186 U.S. 1, 9 (1902). The Siting Board, therefore, must reject any argument that would require us to ignore the circumstances surrounding this proceeding. Further, the history surrounding the enactment of our statute provides additional circumstances that must be considered.[32] The Siting Board must then use honest judgment as to what is just and proper in deciding whether to reopen hearings. Thus, in determining whether to exercise its discretion, the Siting Board must consider the specifics of the Court's directive in Attorney General v. Siting Board, the state of the existing record, and the historical context of the Siting Board's statutory mandate.

With respect to considering the Court's directive in Attorney General v. Siting Board, the Siting Board's actions in response to the Court's directive in City of New Bedford are instructive. In that decision, the Court remanded this matter to the Siting Council "to compare alternative resources in its review of Eastern's application," and raised four "Other Issues which may Arise on Remand to the Council." 413 Mass. at 484, 489-490. In his determination of the procedures that would be followed to address the Court's directive after

32. The Siting Board notes that the Court has held that: "[s]tatutes are to be interpreted, not alone according to their strict verbal meaning, but in connection with their development, their progression through the legislative body, the history of the times, [and] prior legislation ...." Wilcox v. Riverside Park Enterprises, Inc., 399 Mass. 533, 535 (1987), quoting, Commonwealth v. Welosky, 276 Mass. 398, 401 (1931).

that remand, the Hearing Officer found that the Court's directive was specific and required reconsideration only of the five issues identified by the Court (Hearing Officer Memorandum, October 1, 1992). In that memorandum, the Hearing Officer noted that, as all parties had a full and fair opportunity to develop the record on those issues, there was no reason to reopen the record for further development (id. at 6, 7). Nevertheless, the Hearing Officer agreed to allow parties to address those issues by accepting new evidence provided that it was shown that evidence was not previously available (id. at 8).[33] It was only after an agreement by three of the parties to the proceeding that the Hearing Officer allowed a more extensive reopening of the record, although again the reopening was restricted only to those issues raised by the Court's decision in City of New Bedford. The result of that process, as noted above, was a record on those limited issues that was almost as extensive as the original record.

In this docket, rather than requiring the parties to provide new updated evidence that was not previously available as he had in the previous remand, the Hearing Officer requested Offers of Proof and Rebuttals in order to assist him in determining whether the record evidence remained valid and sufficient or whether the record needed to be reopened in order to address the Court's directive.[34] Here the Siting Board reviews those Offers of Proof and

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33 The Siting Board notes that, during the period between EEC's initial filing and the remand proceedings, the state and region experienced a major economic slowdown that directly impacted the validity of the need projections in the EEC Decision. The need projections in that decision, which were based on substantially accurate historical information and reasonable statistical projection methods as required by the statute, forecasted continued growth (22 DOMSC at 211-220, 222-227, 233-241). The Hearing Officer, therefore, was prepared to accept previously unavailable information on the issue of need for the proposed facility due to the potential for significant changes in the need projections. Such a general or technical fact, i.e., that major economic changes will impact future need for energy resources, was clearly within the "specialized knowledge" of the Siting Council within the meaning of G.L. c. 30A, § 11(5), on which to conclude that the introduction of new evidence of need would be appropriate.

34 As noted in Section I.C.1, and note 23, above, the Hearing Officer's request for Offers of Proof was not a request that parties enter new evidence into the record. (continued...)

Rebuttals, mindful that, although presented with several other issues on appeal, unlike in City of New Bedford, the Court's only stated concern with the EEC (remand) Decision was with the lack of an independent finding of need.

As an initial matter, the Siting Board notes that all parties in their Offers of Proof agreed that the record should not be reopened, although they differed as to the conclusions which the Siting Board should draw from the existing record. Although EEC argued that the record supports approval of its petition, the remaining three commenters argued, in essence, that the record was sufficient and valid for purposes of denying the petition, but not so if the petition was to be approved. The Attorney General went further and argued that the Siting Board could not approve the project without reopening the record, as to do so would be inconsistent with the siting statute and the Court's opinion and would be legal error. However, the Attorney General failed to cite language either from the statute or from the Court decision in support of his assertion. Neither did he explain how the discretion which the Court specifically gave to the Siting Board in this matter is consistent with a hard-and-fast rule requiring either the rejection of EEC's petition or the reopening of the record. It is the Siting Board's judgment that the determination of what is just and proper under the circumstances surrounding this proceeding is considerably more complex.

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[34](...continued)

Rather, the Hearing Officer's request was to identify evidence that would justify a finding by the Siting Board as to the continued validity and sufficiency of the existing record such that the Siting Board could respond to the Court's directive. Such an offer of proof is comparable to an offer of proof made during a judicial proceeding that would identify evidence to allow the presiding officer or appeals court to make a determination as to whether that information should be allowed into the record of the judicial proceeding.

The Siting Board notes that any evidence submitted with the Offers of Proof would become a part of the record in this proceeding to be considered by the Hearing Officer and staff in the preparation of a tentative decision if, and only if, a finding were made that it was necessary to reopen the record. The Siting Board acknowledges that such a finding would then result in the evidence submitted being subject to discovery, cross-examination, and rebuttal as per the requirements of G.L. c. 30A, § 11.

Such a determination requires the Siting Board to acknowledge that it and its predecessor agency, the Siting Council, were empowered to oversee a process whereby the Commonwealth's future energy needs would be identified early enough so that plans to meet those needs could be approved, and actions to meet those future needs could be taken. The parties to this proceeding may differ as to the extent and timing of future need, but if projections of need are subject to continued evaluation, timely action to meet those future needs may be prevented. Such possibilities were seen by the Legislature when it first studied the problems associated with siting energy facilities.

The Massachusetts Electric Power Plant Siting Commission ("Siting Commission"), the commission responsible for the drafting of the initial siting legislation, was concerned that a collision of "contradictory public attitudes about electric power" could slow the orderly development of essential power supplies. Third Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6190, March 30, 1973 ("Third Report").[35] The Siting Commission sought to mitigate two factors it perceived as delaying new and needed capacity, i.e., insufficient public notice and environmental challenges. Id. at 8, 9, 15. The enactment of Sections 69G through 69J of G.L. Chapter 164 was aimed at addressing these two concerns. Id. at 15, 20. Thus, the siting statute envisioned the approval of facilities before a need for such facilities actually existed.

To establish future need and ensure timely action to meet such need, G.L. c. 164, § 69I required all electric companies to file annual long-range forecasts for the ensuing ten-year period with respect to the power needs and requirements of their market area. With respect to an electric utility that is required to file such forecasts, the Siting Board may approve a petition to construct a facility only if it is consistent with the company's most recently approved long-range forecast.[36] G.L. c. 164, § 69J. With respect to an electric

[35] A more complete analysis of the activities of the Siting Commission can be found in the EEC (remand) Decision, 1 DOMSB at 246-251.

[36] Accordingly, after a Siting Board review, consistent with the requirements of G.L. c. 164, § 69J, an electric utility proposal to construct a facility could be approved up to ten years prior to its on-line date, assuming that the most recently approved long-range forecast for that utility indicated a need for the facility in that year.

company with no set market area, i.e., a non-utility developer, the Siting Board has required comparable long-range forecasts of power needs and requirements in conjunction with its petition for approval of a proposed facility. Approval of a non-utility developer's petition to construct a facility, therefore, is appropriate if the Siting Board finds that the long-range forecasts demonstrate a need for the proposed facility.[37]

The Siting Board acknowledges that future need for electric power is dependent on numerous factors, any one of which, if altered, could affect the ultimate timing of need. The Siting Board finds that its statute requires that projections of future need must be based on substantially accurate historical information and reasonable statistical projection methods. G.L. c. 164, §§ 69I & 69J. In the present proceeding, the Siting Board and its predecessor agency conducted an analysis of need forecasts for the region consistent with the statutory guidelines that are contained in G.L. c. 164, § 69J in two separate decisions. In the remand proceedings, the Siting Board responded to the Court's directive raised in City of New Bedford, that the statute requires a finding of Commonwealth need, and conducted a Massachusetts need analysis in addition to the regional need analysis. EEC (remand) Decision, 1 DOMSB at 466-495. The Siting Board finds that the existing record on both regional and Massachusetts need is extensive and provided sufficient evidence to support an independent finding regarding need at the time that the EEC (remand) Decision was issued. Therefore, as the Siting Board has undertaken the analysis of need required under its statute and as directed by the Court in City of New Bedford, and no party has identified any information that would lead the Siting Board to conclude that the record is insufficient to do so, the Siting Board also finds that the record evidence is sufficient to respond to the Court's directive. Accordingly, the Siting Board now looks to the continued validity of the record evidence.

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37 In City of New Bedford, the Court acknowledged the Siting Council's argument "that the review format of the long-range forecast is not easily applied to a non-utility producer." 413 Mass. at 488. The Court stated that modifications to the procedure may be necessary to accommodate the non-utility producer but cautioned that any such modifications "must permit a review that fulfills the statutory mandate." Id.

Findings of future need that are based on such substantially accurate historical information and reasonable statistical projection methods are not rendered inaccurate or in violation of the statute simply with the passage of time. Thus, the Siting Board finds that in an ongoing proceeding such as this, it is only if evidence of a nature that would demonstrate that one or more factors that affect the historical information or statistical projection methods have significantly changed that findings of future need based on such information or methods would be brought into question. The Siting Board does not adopt the standard proposed by EEC that there must be "compelling new evidence" before the record is reopened. However, the Siting Board concludes that sufficient evidence to indicate that future projections are significantly changed should be required.

With regard specifically to the future demand for electricity, all commenters noted that if the record were reopened, the Siting Board should consider recent versions of the CELT report that are not contained in the existing record. Some parties asserted that the more recent reports would show that load growth has slowed such that need for additional generating capacity would not arise until later than the year 2000. However, these parties did not provide sufficient justification for their assertion that the more recent CELT reports would support an expectation of a significant delay of need beyond the year 2000.[38] In contrast, we note that the Company submitted affidavits which, if entered into the record, would explain how these same CELT reports show that need would actually occur one or more years prior to 2000.

Since the Siting Board has determined that the record should be reopened only in light of sufficient evidence that would indicate that projections of future need are significantly changed, we must consider whether the existence of later CELT reports constitutes such evidence. This requires a review of our consideration of those CELT reports that are present in the record. The Siting Board notes that all the CELT reports that were previously admitted into the record have been subjected to numerous corrections, analyses and other

38 The Siting Board notes that, although the Attorney General focussed on reduced growth in demand as an indicator that need would be later than the year 2000, consideration of both demand and supply would be required to address the likelihood of a significant delay in the year of need.

manipulations by the parties to the proceeding. Thus, the information provided in the CELT reports amounts to a starting point for analysis, not a definitive statement as to future need.[39] Indeed, if the CELT reports could serve that purpose, the Siting Board's independent finding of need, although it would still be required by the statute as the Court has indicated, would be superfluous.

Given the experience with adjustments to those CELT reports that are in the existing record, the Siting Board has no independent basis to conclude that more recent CELT reports necessarily provide more accurate demand projections than earlier CELT reports. Of those making Offers of Proof regarding the later CELT reports, only EEC addressed the accuracy of those reports. However, EEC's analysis does not provide convincing evidence indicating that an examination of more recent CELT reports is likely to result in a substantial change in the year of need. Thus, no party's offer of proof provides clear reason for the Siting Board to reopen the record, based on any expectation that review of more recent CELT reports is likely to lead to a finding of substantially earlier or later need.

The Siting Board finds that no party has provided any support for its conclusion that the more recent CELT reports provide substantially different and more accurate information or demonstrate that those CELT reports currently in the record are invalid.[40] Accordingly, the Siting Board finds that it has no basis on which to conclude that the analyses of need based on those CELT reports that are currently in the existing record are any less valid today than when they were previously conducted. Further, the Siting Board has no basis on which to conclude that the more recent CELT reports, standing alone, would better enable it to respond to the Court's directive.

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39 Our rejection, after a complete analysis, of the 1991 CELT Report (see, EEC Decision, 22 DOMSC at 235-236) illustrates that CELT reports are not to be treated any differently than any other piece of evidence that is submitted.

40 The Siting Board acknowledges that the later CELT reports were not available at the time the record was closed, but is unable to conclude that a later report is necessarily more accurate based on its having been issued at a later time, without the identification of information on that point.

With regard to other issues raised by the parties in their Offers of Proof that may be considered to be indirectly related to the issue of need, the Siting Board finds that no party provided more than assertions that issues addressed in the EEC (remand) Decision have changed substantially. The Siting Board carefully reviewed long-range forecasts of economic growth and DSM in the EEC (remand) Decision and no party has identified any information that would support a finding that these forecasts are no longer valid. While the possible future restructuring of the electric power industry may affect demand for electricity at some time in the future, uncertainty about the timing and the nature of such restructuring is so great that no party could provide anything more than conjecture on this topic. Such conjecture, unsupported by any facts or even current statements of policy, cannot serve as a basis for concluding that the existing record is invalid or insufficient. The Attorney General's arguments that recent federal appliance efficiency legislation would affect need ignores the fact that the projections of future need in the EEC (remand) Decision did account for savings that would result from such mandated federal standards (see, Exhs. HO-RR-38 at 2-11; HO-70 at 46).

In addition, the Siting Board finds that none of the parties has identified any other evidence, as requested by the Hearing Officer, that would indicate that the Siting Board's analysis of need in the EEC (remand) Decision is no longer valid or is based on insufficient evidence, such that we are compelled again to revisit the issue of need. Further, the Siting Board finds that none of the parties has identified other factors that would compel us to reopen the record. Finally, the Siting Board finds that it does not have independent general, technical or scientific facts within its specialized knowledge which would lead it to determine that the existing record is invalid or insufficient.[41]

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41 The Siting Board notes that during the period between the EEC (remand) Decision and this decision, the state and region did not undergo major changes in the economy similar to those experienced during the period between EEC's initial filing and the remand proceedings (see note 33, above). More importantly, no party has identified any evidence that would support a finding by the Siting Board that current economic conditions are different than those that were used in the need projections in the EEC (remand) Decision. Accordingly, the Siting Board has no basis on which to conclude (continued...)

4. Findings and Conclusions

In Section I.C.3, above, the Siting Board has found that:

- the scope of the Court's directive in Attorney General v. Siting Board is very specific and is limited to the requirement that the Siting Board make an independent finding of need and not rely on signed and approved PPAs to take the place of such a finding (p. 21);
- it must determine whether the existing record evidence on which its findings of need are based remains valid and sufficient (p. 21);
- its statute requires that projections of future need must be based on substantially accurate historical information and reasonable statistical projection methods. G.L. c. 164, §§ 69I & 69J (p. 26);
- the existing record on both regional and Massachusetts need is extensive and provided sufficient evidence to support an independent finding regarding need at the time that the EEC (remand) Decision was issued (p. 26);
- the record evidence is sufficient to respond to the Court's directive (p. 26);
- in an ongoing proceeding such as this, it is only if evidence of a nature that would demonstrate that one or more factors that affect the historical information or statistical projection methods have significantly changed that findings of future need based on such information or methods would be brought into question (p. 27);
- no party has provided any support for its conclusion that the more recent CELT reports provide substantially different and more accurate information or demonstrate that those CELT reports currently in the record are invalid (p. 28);
- it has no basis on which to conclude that the analyses of need based on those CELT reports that are currently in the existing record are any less valid today than when they were previously conducted (p. 28);

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[41](...continued)
that the introduction of new evidence on need would do any more than provide an opportunity to relitigate an issue that already has been resolved.

- no party provided more than assertions that issues addressed in the EEC (remand) Decision have changed substantially (p. 29);
- none of the parties has identified any other evidence, as requested by the Hearing Officer, that would indicate that the Siting Board's analysis of need in the EEC (remand) Decision is no longer valid or is based on insufficient evidence, such that we are compelled again to revisit the issue of need (p. 29);
- none of the parties has identified other factors that would compel us to reopen the record (p. 29); and
- it does not have independent general, technical or scientific facts within its specialized knowledge which would lead it to determine that the existing record is invalid or insufficient (p. 29).

Accordingly, the Siting Board concludes that the existing record evidence on which its need analyses in the EEC (remand) Decision were based remains valid and can serve as the basis for an independent finding of need in response to the Court's directive in Attorney General v. Siting Board.

As the Offers of Proof and Rebuttals provided to the Siting Board fail to identify information that would lead the Siting Board to conclude that the existing record is either invalid or insufficient or that the need projections have significantly changed, the Siting Board will not, based on conjecture and supposition, reopen the record. The Siting Board concludes that to do so would be contrary to the Court's discussion in Paquette v. Fall River, supra., in that it would amount to an arbitrary action that is not just and proper under the circumstances, and therefore would amount to an abuse of the discretion afforded the Siting Board by the Court.

In making such a determination, the Siting Board is mindful of the Legislature's concern, as expressed in the Third Report, that new and needed capacity could be delayed. The need to plan in advance for future requirements dictates a reasonable limitation on analysis and a move to action on that analysis at some point. Where, as here, the Court has identified one legal error in the EEC (remand) Decision, the Siting Board concludes that it would be contrary to legislative intent to allow for a relitigation of issues likely to be, using the Attorney General's words, "as extensive as, or more extensive than" prior evaluations. The history of this proceeding demonstrates the potential for such an outcome. Where no evidence has been identified by the parties that would lead the Siting Board to conclude that the existing record was insufficient to address, or no longer valid for addressing, the sole issue raised by the Court after affording all parties an opportunity to do so, the Siting Board can find no reason to further delay these proceedings by reopening the record, and will address the Court's directive based on the existing record.[42]

The Siting Board notes that its decision not to reopen the record in this case is not inconsistent with its decision to reopen the record in response to the Court's directive in City of New Bedford. First, as noted above, the Court's directive was significantly more limited in scope in Attorney General v. Siting Board than in City of New Bedford.

Further, the record developed in the EEC Decision was neither sufficient nor valid to respond to the Court's directive in City of New Bedford. The Court's directive required reconsideration of two issues for which a full record was not developed in the EEC Decision -- the comparison of alternative resources and the analysis of Massachusetts need.[43] In

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[42] Had no record been developed on the issue of need, the Siting Board would have been in a comparable position to the Department in the Court's recent decision in Boston Edison Company v. Department of Public Utilities, and would have needed to reopen the record. 419 Mass. 738 (1995). In that case, the Department found it unnecessary to reopen the record to consider an offer of proof on an issue that had not been reviewed, i.e., Boston Edison's avoided costs in light of the deferral of its proposed generating plant. Id., 419 Mass. at 744, 746. In contrast, as the Court has recognized in this proceeding, the Siting Board has reviewed the issue of future need, based on a record that was fully developed by all parties, in direct response to the Court's earlier directive. As no party has identified information that would establish that the existing record was either insufficient (as in Boston Edison) or no longer valid for purposes of reviewing future need and responding to the Court's concern in Attorney General v. Siting Board, the Siting Board has exercised the discretion afforded it by the Court and decided that, to reopen the record would not be just and proper under the circumstances surrounding this proceeding. See, Paquette v. Fall River, 278 Mass. at 172.

[43] In its original filing the Company provided a comparison of alternatives consistent with past Siting Council practice and an analysis of Massachusetts need. EEC (continued...)

addition, new evidence of need was appropriate due to the major economic slowdown during the period between EEC's initial filing and the remand proceedings (see n.33, above). In contrast, a sufficient record has been developed in the EEC (remand) Decision to address the Court's one stated concern in Attorney General v. Siting Board. Further, as stated in note 41, above, there has been no major change in the state or regional economy between the EEC remand Decision and this decision similar to the major economic slowdown experienced between EEC's initial filing and the remand proceedings. Finally, as stated in note 41, above, no party has identified any information that would support a finding by the Siting Board that current economic conditions are different than those used in the need projections in the EEC (remand) Decision.

Having determined that no evidence has been identified by the parties that would lead the Siting Board to conclude that the existing record is either invalid or insufficient to respond to the Court's directive in Attorney General v. Siting Board, and having no independent basis on which to make such a determination, the Siting Board, therefore, will consider the existing record in making its independent determination as to the need for EEC's proposed facility. Before doing so, however, the Siting Board must revisit those findings in the EEC (remand) Decision that the Court has indicated were improper.

[43](...continued)
(remand) Decision, 1 DOMSB at n. 88, n.259. However, the Siting Board did not evaluate these analyses in the EEC Decision. EEC Decision, at 267-285; EEC (remand) Decision, 1 DOMSB at n.259.

II. ANALYSIS OF THE PROJECT[44]

A. The Final Decision in EFSB 90-100R

1. Identification of Affected Findings

The following excerpts from the EEC (remand) Decision constitute the Siting Board's requirements of EEC relative to the submission of PPAs. In accordance with the Court's directive in Attorney General v. Siting Board, the Siting Board hereby rescinds these requirements of the Company and amends its EEC (remand) Decision by deleting from it the following language.

- The Siting Board finds that the existence of a signed and approved PPA with a Massachusetts utility will continue to be one method of establishing Massachusetts Need, although clearly, not the only method. EEC (remand) Decision, 1 DOMSB at 419, 421.

- The Siting Board also finds that the amount of facility output subject to signed and approved PPAs that would be sufficient to establish Massachusetts need will depend on other factors which contribute to Massachusetts need as well as the size and type of facility. Id.

- The Siting Board notes that, in addition to an analysis of regional and Massachusetts capacity need, the standard of review set out in Section II.C.2.d, above, identifies signed and approved PPAs with capacity payments as a means of establishing need for additional energy resources on reliability grounds. Therefore, in light of the uncertainty surrounding the first year of need for the proposed project, the Siting Board finds that, in this case, it is appropriate to require the Company to submit such PPAs as evidence of the need for the proposed project to provide a necessary energy supply for the Commonwealth. The Siting Board has found that the amount of facility output subject to signed and approved PPAs that would be sufficient to establish Massachusetts need will depend on other factors which contribute to Massachusetts need as well as the size and type of facility (see Section II.C.2.d, above). Here, in light of the need for the proposed project beginning in the year 2000, the Siting Board finds that submission of (1) signed and approved PPAs which include capacity

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44 In determining whether a proposed project will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board conducts a broad analysis addressing a number of specific issues: (1) need for additional energy; (2) alternative project technologies; (3) project viability; and (4) site selection, facility environmental impacts, facility costs and facility reliability. In this proceeding, as discussed in Section I.A, above, the Siting Board has issued three decisions that collectively address these issues.

payments for at least 75 percent of the proposed project's output, and (2) signed and approved 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 § 94A, will be sufficient evidence to establish that the proposed project will provide a necessary energy supply for the Commonwealth. EEC must satisfy this condition within four years from the date of this conditional approval. EEC will not receive final approval of its project until it complies with this condition. The Siting Board finds that, at such time that EEC complies with this condition, EEC will have demonstrated that the proposed project will provide a necessary energy supply for the Commonwealth. Id., 1 DOMSB at 498-499.

- Further, the Siting Board has found that at such time as EEC complies with the condition set forth in Section II.C.5, above EEC will have demonstrated that the proposed project will provide a necessary energy supply for the Commonwealth. Id., 1 DOMSB at 499, 509.

2. Status of Remaining Findings

In City of New Bedford, after noting the Siting Council's failure to conduct an analysis of alternatives, the Court identified several other issues of concern. In Attorney General v. Siting Board, although presented with several issues on appeal, the Court faulted the Siting Board only for its failure to make an independent finding of need and its reliance on PPAs in place thereof and did not identify any other issues of concern. The Court also did not disturb any of the subsidiary findings in the EEC (remand) Decision except as they relate to the issue of the independent finding of need and the reliance on PPAs.

In the EEC (remand) Decision, the Siting Board noted that the findings in the EEC Decision and EEC Compliance Decision, beyond those specifically remanded by the Court, remained in effect and there was, therefore, no reason to revisit them. 1 DOMSB at 509. The findings in the EEC (remand) Decision, beyond those identified in Section II.A.1, above, are based on the record evidence, which the Siting Board has concluded in Sections I.C.3 and I.C.4, above, to be sufficient and valid. Accordingly, the Siting Board reaffirms all of the other findings, conditions, and recommendations in the EEC (remand) Decision and hereby incorporates them by reference.[45]

B. Need Analysis

1. Introduction

As discussed in Sections II.A.1 and II.A.2, above, the Court's decision in Attorney General v. Siting Board was confined to the findings and condition associated with need for the proposed facility, and specifically the condition pertaining to the reliance on signed and approved PPA's. In the following section we review our findings on the issue of need for EEC's proposed project.

2. The Commonwealth's Need for Additional Energy Resources

In response to the Court's directive in City of New Bedford, the Siting Board set forth the following standard of review for evaluating need for non-utility developers:[46]

> 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 on reliability, economic or environmental grounds directly related to the energy supply of the Commonwealth.

EEC (remand) Decision, 1 DOMSB at 423.

Therefore, in order to evaluate the need for the proposed project on reliability grounds, the Siting Board reviewed forecasts of demand and supply, which were provided by

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45 The Siting Board has included the findings relative to the issue of need from the EEC (remand) Decision in Appendix A to this decision.

46 The Siting Board notes that this standard of review would be identical for an electric utility proposing to construct a facility to meet a Commonwealth need as opposed to its own need. If such an electric utility were proposing to construct a facility to meet its own needs, the Siting Board would only need to review that utility's most recently approved long-range forecast. Thus, the Siting Board's need analyses for electric utilities and non-utility developers are comparable.

the parties and made part of the existing record, for both the New England region and the Commonwealth. Id., 1 DOMSB at 423-459, 466-491. The Siting Board review focussed on demand forecast methodologies and estimates of DSM savings over the forecast period, and supply forecasts, including the capacity assumptions, contingency adjustments, and required reserve margin assumptions. Id. The Siting Board then reviewed the need forecasts, which are based on a comparison of the various demand and supply forecasts. Id., 1 DOMSB at 460-465, 491-495.

Based on this extensive analysis, the Siting Board found that Massachusetts will have a need for an amount of capacity equal at least to that of EEC's proposed facility by the year 1998. Id., 1 DOMSB at 495. The Siting Board also found that there will be a need for 300 MW of additional energy resources in New England for reliability purposes beginning in 2000. Id., 1 DOMSB at 497. The Siting Board further found that (1) Massachusetts' need for 300 MW of additional capacity will occur earlier than New England's need for the same, and (2) it is clear that, for all years in which there will be a regional need for EEC's proposed project, i.e., for the years 2000 and beyond, said project would provide a necessary energy supply for the Commonwealth. Id. at 498.

This analysis also showed that surplus supply in parts of the region in the years 1998 and 1999 might be available to meet the Commonwealth's need in those years, although the record was unclear regarding the ability of Massachusetts utilities to acquire surplus supplies from out-of-state providers in those years. Id. The Siting Board concluded that there was insufficient evidence to establish that there would be any Massachusetts need until at least the year 2000.[47] Id. Finally, the Siting Board found that for all years in which there will be a regional need for EEC's proposed project, i.e., for the years 2000 and beyond, said project would provide a necessary energy supply for the Commonwealth. Id.

The Court has acknowledged that the Siting Board reviewed numerous capacity and demand forecasts in reaching the conclusion that the proposed project was not needed to provide a necessary energy supply for the Commonwealth prior to the year 2000. Attorney

[47] The Siting Board agrees with the Attorney General and rejects EEC's argument that the existing record supports a finding of need earlier than the year 2000.

General v. Siting Board, 419 Mass at 1004. The Attorney General has acknowledged that (1) over one hundred pages of need analysis culminated in the finding that the record did not support a finding of need before the year 2000, and (2) the Court did not disturb the Siting Board finding that a regional surplus existed in the years 1998 and 1999 but not beyond (Attorney General Rebuttal at 4). EEC noted that the Siting Board had determined that its proposed facility would constitute a necessary energy supply for the Commonwealth beginning in the year 2000 and continuing thereafter (EEC Offer of Proof at 5, citing, EEC (remand) Decision, 1 DOMSB at 498). And finally, no party challenged on appeal the finding that the Commonwealth will have a need for an amount of capacity equal at least to that of EEC's proposed facility in the year 2000 and beyond.

Accordingly, the Siting Board finds that the existing record clearly establishes a need for reliability purposes in the Commonwealth in the year 2000 and beyond for an amount of capacity equal at least to that of EEC's proposed facility.[48]

The Siting Board must, therefore, determine whether EEC's proposed facility will be available to meet that need in the year 2000. In its initial petition, EEC proposed an initial on-line date of 1994 (Exh. HO-1A at 46). EEC introduced evidence in the first set of hearings in this proceeding that established that the construction schedule for the proposed facility would take 47 months following financial closing (Exh. HO-PV-1). No party has challenged this evidence in either appeal of the Siting Council or Siting Board's decisions, and no party has identified any evidence that it would provide, were the record to be reopened, that is contrary to such a timetable for construction.

Following the Court's decision in City of New Bedford, EEC's subsequent filing indicated that the earliest possible on-line date would be 1997. The record did not indicate that the proposed facility would, in fact, come on-line in 1997, but rather that after EEC received Siting Board approval, EEC would act to finalize its financial arrangements after which it would take an additional 47 months before the facility would be available to sell

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48 The Siting Board notes that this finding follows inevitably from the unchallenged subsidiary findings in the EEC (remand) Decision, and does not constitute a "recasting of the evidence" of the sort against which the Attorney General has properly cautioned us.

power. Following the remand, the earliest possible date for this purpose was 1997. Accordingly, the Siting Board premised its analyses in the EEC (remand) Decision on the assumption that the first year of availability of the proposed facility and of the alternatives would be 1997.[49]

At this point in time, if the final Siting Board approval is granted in the summer of 1995, the earliest possible on-line date for EEC's proposed facility would be the summer of 1999. This assumes that (1) financial closing also occurred in the summer of 1995, and (2) no further judicial proceedings are required. As it is likely that financial closing will take, at a minimum, several months, the Siting Board finds that EEC's proposed facility will come on-line no earlier than the summer of 1999, and probably not until some time during the year 2000.[50]

The Attorney General, however, has argued that the Siting Board cannot recognize that the on-line date of the proposed facility has been delayed from 1997 to 1999 or 2000 without doing a complete recomparison of the alternatives using updated information, since renewable technologies and cleaner generations of fossil fuel plants are becoming more readily available and the relative costs of the alternative technologies has changed (Attorney General Offer of Proof at 7-8; Attorney General Rebuttal at 6-7). The Siting Board rejects this argument for the following reasons.

With regard to changes in technology, no new evidence has been identified by any party that is likely to alter the Siting Board's finding that non-conventional technologies such as municipal solid waste, biomass, wind, solar-photovoltaic cells, fuel cells, geothermal and hydroelectric alternatives, several of which can be classified as renewable technologies, are not reasonable alternative approaches to meeting a need of the size identified in the

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49 The Siting Board recognizes that proposed on-line dates are subject to change for a variety of reasons over which the developer has little or no control. The Siting Board, however, must choose some point in time as a starting-point for cost comparisons that require the use of inflation factors and other associated adjustments.

50 The Siting Board agrees with the Company that the Siting Board has determined that it is appropriate to explicitly consider need within a time frame beyond the first year of facility operation. EEC (remand) Decision, 1 DOMSB at 463.

projections of need in the EEC (remand) Decision. 1 DOMSB at 498. In addition, the Attorney General did not identify any information regarding the availability of cleaner generations of fossil fuel plants or further advancements in coal gasification technology or the likelihood of that technology reaching maturity by the year 2000, that he could provide to the Siting Board beyond that presented by his witness in the remand proceedings. See, EEC (remand) Decision, 1 DOMSB at 378.

With regard to the cost comparison of the technology alternatives, the Attorney General argued that the Siting Board's analysis is no longer valid due primarily to decreases in the cost of natural gas in the New England region (Attorney General Offer of Proof at 7). However, the Siting Board's cost analysis was based on the 20-year levelized cost of the technology alternatives, rather than specific yearly costs. Initial 1993 fuel prices were adjusted by various fuel price forecasts to estimate fuel prices for 20 years of facility operation. Even if the current cost of natural gas has declined, the Attorney General has not identified any information that he could provide to the Siting Board to establish that what may be a short-term perturbation is inconsistent with the long-range projection of natural gas prices that served as a basis for the Siting Board's analysis in the EEC (remand) Decision. Further, the Attorney General has not identified any information that he could provide to the Siting Board regarding changes in projections of the relative prices of coal and natural gas.

The Siting Board notes that its statute explicitly provides for the conditional approval of petitions to construct jurisdictional facilities. G.L. c. 164, § 69J. Such conditions may include prerequisites for establishing viability, as well as design or mitigation conditions related to minimizing environmental impacts. The Siting Board further notes that, whenever it exercises its statutory authority to approve the construction of a facility subject to need or viability conditions, it accepts the continuing validity of those portions of its analysis upon which it does not place conditions. If facilities were repeatedly refused approval because a newer technology, which may have some marginal benefit over the facility under review, has been developed, needed power facilities could not be approved and constructed in a timely fashion. For this reason, the Siting Board establishes a deadline for compliance with the conditions of such approvals.

In the Eastern (remand) Decision, the Siting Board allowed EEC four years from the date of the conditional approval to submit signed and approved PPAs to establish the need for the proposed project. 1 DOMSB at 499. In doing so, the Siting Board accepted the continuing validity of its analysis of alternatives so long as EEC complied with the conditions of the approval regarding need for the project by October 27, 1997. The Siting Board was fully aware that, if EEC did not receive final approval until October 1997, it would not be constructed and operational until late in 2001. Thus, a delay in the project's on-line date until the year 2000 is a contingency that was provided for and accepted in the Eastern (remand) Decision, and does not affect the continuing validity of the analysis of alternatives conducted in that decision.

Accordingly, the Siting Board finds that, as no party has identified information that would lead the Siting Board to conclude that its analysis of alternative technologies, based on their 20-year levelized cost, is now invalid, the Siting Board has no reason to revisit this analysis.[51] Therefore, the Siting Board finds that its analyses in the EEC (remand) Decision, which demonstrate that the levelized costs for EEC's proposed facility show that it will be a least-cost addition to the Commonwealth's energy supply, and that the proposed facility is superior to all alternative technologies reviewed with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost (1 DOMSB at 397), remain valid if the on-line date of the proposed facility is changed from the year 1997 to the year 2000.

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51 The Siting Board also dismisses EEC's argument that a review of other project costs would potentially give the proposed facility a cost advantage, relative to the technology alternative, for the same reason. EEC has not identified information that would lead the Siting Board to conclude that its 20-year levelized cost of alternative technologies analysis is now invalid.

3. Findings and Conclusions

In addition to the subsidiary findings on need made in the EEC (remand) Decision and listed in Appendix A, the Siting Board has found that:

- Massachusetts will have a need for an amount of capacity equal at least to that of EEC's proposed facility by the year 1998. [EEC (remand) Decision,] 1 DOMSB at 495 (p. 37);
- there will be a need for 300 MW of additional energy resources in New England for reliability purposes beginning in 2000. Id., 1 DOMSB at 497 (p. 37);
- (1) Massachusetts' need for 300 MW of additional capacity will occur earlier than New England's need for the same, and (2) it is clear that, for all years in which there will be a regional need for EEC's proposed project, i.e., for the years 2000 and beyond, said project would provide a necessary energy supply for the Commonwealth. Id. at 498 (p. 37);
- the existing record clearly establishes a need for reliability purposes in the Commonwealth in the year 2000 and beyond for an amount of capacity equal at least to that of EEC's proposed facility (p. 39); and
- EEC's proposed facility will come on-line no earlier than the summer of 1999, and probably not until sometime during the year 2000 (p. 40).

Consequently, the Siting Board finds that there will be a need for reliability purposes in the Commonwealth for the EEC facility beginning in its first, or at latest, its second, year of operation.

The Siting Board has determined that it is appropriate to consider need explicitly within a time frame beyond the first year of facility operation. EEC (remand) Decision, 1 DOMSB at 463. In the EEC (remand) Decision, the Siting Board explained that, if need has been established for the first year of operation, reviewing need over a longer time frame helps ensure that the need will continue for a number of years. 1 DOMSB at 464. Further, 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. Id.

Here, the timing of Commonwealth need, as established above, exactly matches the most probable first year of operation of the EEC facility. Consequently, the Siting Board finds that the EEC facility will provide a necessary supply of energy for the Commonwealth.

In Section II.B.2, above, the Siting Board also found that:

- as no party has identified information that would lead the Siting Board to conclude that its analysis of alternative technologies, based on their 20-year levelized cost, is now invalid, the Siting Board has no reason to revisit this analysis (p. 41); and
- its analyses in the EEC (remand) Decision, which demonstrate that the levelized costs for EEC's proposed facility show that it will be a least-cost addition to the Commonwealth's energy supply, and that the proposed facility is superior to all alternative technologies reviewed with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost (1 DOMSB at 397), remain valid if the on-line date of the proposed facility is changed from the year 1997 to the year 2000 (p. 41).

Consequently, the Siting Board reaffirms its finding that the proposed facility is superior to all alternative technologies reviewed with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

C. Conclusions on the Proposed Project

Based on the record evidence, developed by all parties to these proceedings, the Siting Board has found that the EEC facility will provide a necessary supply of energy for the Commonwealth. Further, the Siting Board has reaffirmed its finding that the proposed facility is superior to all alternative technologies reviewed with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, based on the existing record as analyzed and set forth in the EEC Decision and the EEC Compliance Decision, as amended in response to the (1) directives of the Court in City of New Bedford, by the analyses contained in the EEC (remand) Decision and, (2) directive of the Court in Attorney General v. Siting Board, by this decision, the Siting Board finds that the proposed EEC facility will provide a necessary energy supply for the Commonwealth with, on balance, a minimum impact on the environment at the lowest possible cost.

III. DECISION

In Attorney General v. Siting Board, the Court vacated the Siting Board's decision conditionally approving the siting of EEC's proposed facility due to the failure of the Siting Board to make an independent finding of need for that facility. 419 Mass. at 1005. The Court left to the discretion of the Siting Board the determination as to whether to reopen hearings. Id.

Based on a review of pertinent Court decisions, the Siting Board determined that such discretion requires a review of circumstances surrounding the proceeding and the historical context of its statute in order to identify appropriate procedures to follow to address the Court's directive that the Siting Board make an independent finding of need. The Siting Board determined that all parties had been provided a full opportunity to develop a record as to the issue of need over the course of more than four years. Further, the Siting Board determined that an extensive record on need had been developed in which regional need had been analyzed on two separate occasions, in addition to a complete analysis of Commonwealth need, conducted in direct response to the Court's directive in City of New Bedford. The Siting Board, nevertheless, provided all parties an opportunity to address the issues as to whether that record was sufficient and remained valid for purposes of addressing the Court's concern.

After reviewing the submissions of the parties, the Siting Board has determined that the existing record is sufficient and remains valid for purposes of making an independent finding of need. The Siting Board, therefore, found no reason to exercise its discretion to reopen hearings in this proceeding.

Accordingly, the Siting Board approves the petition of EEC to construct a bulk generating facility and ancillary facilities, subject to the conditions and recommendations set forth in the EEC Decision, the EEC Compliance Decision, and the EEC (remand) Decision, as amended by Section II.A.1, above.

The Siting Board notes that the approval of EEC's petition remains conditional as EEC has yet to submit its filing relative to viability conditions. EEC Decision 22 DOMSC at 312-313. EEC will not receive a final approval of its proposed facility until such time as this condition has been met. The Siting Board requires EEC to comply with this condition within four years of the final EEC (remand) Decision, i.e., by October 27, 1997.

Robert P. Rasmussen
Hearing Officer

Dated this 27th day of June, 1995

APPROVED by a majority of the Energy Facilities Siting Board at its meeting of June 27, 1995 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, EFSB/DPU); Janet Gail Besser (Commissioner, DPU); David L. O'Connor (for Gloria C. Larson, Secretary of Economic Affairs); and Joseph Faherty (Public Member). Voting against approval of the Tentative Decision as amended: Sonia Hamel (for Trudy Coxe, Secretary of Environmental Affairs), and William Sargent (Public Member).

Kenneth Gordon
Chairman

Dated this 27th day of June, 1994

APPENDIX A -- EEC (remand) DECISION
Findings on Need

In Sections II.C.3 and 4, above, the Siting Board has made the following subsidiary findings:

- that the reference forecast is an appropriate base case forecast for use in the analysis of regional demand for the years 1996 through 2007 (p. 211);
- that the expected value forecast is an acceptable forecast for use in an analysis of regional demand, but should not constitute a base case forecast (p. 213);
- that the GDP forecast provides a possible high-case forecast for use in an analysis of regional demand, while recognizing that the forecast methodology is not sophisticated and that possible adjustments may be needed to reflect DSM trends over forecast period (p. 214);
- that it is appropriate to adjust the 1992 CELT DSM levels in the base case (p. 214);
- that an adjustment of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels is reasonable for the purposes of this review (p. 214);
- that the Company's low DSM forecast should be adjusted to represent the 1992 CELT low DSM case (p. 215);
- that the Company's high DSM forecast should be adjusted to represent the 1992 CELT high DSM case (p. 215);
- that the base supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable base supply forecast for the purposes of this review (p. 225);
- that the low supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, represents a reasonable low supply forecast for the purposes of this review (pp. 225-226);
- that the high supply case, including 83 MW of the committed capacity of NUG projects that are existing or under construction, and as adjusted by 66 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 (p. 226);

- that the Company's regional supply contingency analysis provides an acceptable basis for assessing the potential range of regional capacity positions that might arise over the forecast period (p. 228);
- that the Company's reserve margin for the years 1997 through 2000 should be adjusted as follows: (1) 22 percent for 1997; (2) 21.5 percent for 1998; (3) 21 percent for 1999; and (4) 20.5 percent for 2000 (p. 228);
- that it is appropriate to explicitly consider need for the proposed facility within the 1997 to 2000 time period (p. 233);
- that need for 300 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond (p. 234);
- 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 (p. 246);
- 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 (p. 248);
- that the Massachusetts end year CAGR forecast provides an acceptable forecast for use in an analysis of Massachusetts demand (p. 250);
- 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 (p. 252);
- 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

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 Altresco Lynn, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 91-102A

FINAL DECISION

Robert W. Ritchie
Hearing Officer
August 17, 1995

On the Decision:
Barbara Shapiro
Enid Kumin

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I. INTRODUCTION

A. Procedural History

On March 29, 1991, Altresco Lynn, Inc. ("Altresco" or "Company") filed with the Energy Facilities Siting Council ("Siting Council"),[1] a petition to construct a 325 megawatt ("MW"), natural gas-fired cogeneration facility and ancillary facilities in the City of Lynn, Massachusetts. The Siting Council docketed the petition as EFSC 91-102.[2] On October 18, 1991, Altresco submitted a revised petition for construction of a smaller, 170 MW natural gas-fired cogeneration facility and ancillary facilities.

The Siting Council initially conducted 12 days of evidentiary hearings commencing April 16, 1992 and ending June 5, 1992. 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 in response to the Supreme Judicial Court's ("Court") 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 that proposed facility.[3] Id. at 484.

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1 Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), the Siting Council was merged with the Department of Public Utilities ("Department") 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 newly created Energy Facilities Siting Board ("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.

2 Jurisdiction over Altresco's petition originally arose pursuant to G.L. c. 164, §§ 69H and 69I, which required electric companies to obtain Siting Board approval for construction of proposed facilities. Altresco Lynn, Inc., 2 DOMSB 1, 11 (1993). Said jurisdiction is now codified in G.L. c. 164, §§ 69H and 69J. Subsequent to the creation of the Siting Board, this proceeding was re-docketed as EFSB 91-102.

3 In City of New Bedford, the Court also identified four other issues for further consideration:

(continued...)

An evidentiary hearing was held on alternative energy resources on October 30, 1992. At that evidentiary hearing, in response to a motion filed by intervenor Point of Pines Beach Association, Inc. ("Point of Pines"), the Hearing Officer allowed 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. Additional evidentiary hearings were held on February 17, 23, and 24, 1993, on the issue of Massachusetts need. The Hearing Officer entered 376 exhibits into the record, consisting primarily of information and record request responses. Altresco entered 42 exhibits into the record. Point of Pines entered 47 exhibits into the record. Intervenor John Arrigo entered one exhibit into the record.

On November 24, 1993, the Hearing Officers issued the initial Tentative Decision in this proceeding. The Siting Board, by majority vote, adopted the Tentative Decision with some minor amendments at its December 14, 1993 meeting. Altresco Lynn, Inc., 2 DOMSB 1, 225 (1993) ("Altresco Decision").[4]

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[3](...continued)

(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 (413 Mass. 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).

[4] In the Altresco Decision, 2 DOMSB at 222-223, the Siting Board conditionally approved Altresco's petition. The conditions imposed on Altresco fell into three categories: need, viability and environmental. Id. The Siting Board found that there would be a need for 170 MW or more of additional energy resources for reliability purposes beginning in the year 1997 for Massachusetts and beginning in the year 2000 in New England. Id. at 61, 92. The Siting Board also found that Altresco had established that, beginning in 2000 or later, New England will need 170 MW of additional energy resources from the proposed project for economic efficiency purposes. Id. at 68. As it was unclear from the record whether the regional surplus would be available to meet the earlier need for power in the Commonwealth, the (continued...)

A timely joint petition for appeal of the Altresco Decision was filed with the Court sitting in the County of Suffolk by Point of Pines and the City of Revere ("Revere"), both intervenors in the proceeding, pursuant to G.L. c. 164, § 69P, and c. 25, § 5. Altresco filed a motion for leave to intervene in the proceeding, which was granted by the Court. The joint petition for appeal was reported by a single justice to the full Court and docketed as Civil Action SJC-6551.

The Court issued its decision on the appeal on January 11, 1995. Point of Pines Beach Association, Inc. vs. Energy Facilities Siting Board, 419 Mass. 281 (1995) ("Point of Pines v. Siting Board").

B. The Appeal of the Altresco Decision and the Court's Decision in Point of Pines v. Energy Facilities Siting Board

In their joint petition for appeal, Point of Pines and Revere raised several issues as causes of action. The first set of issues related to the Siting Board conditioning approval

[4](...continued)

Siting Board found that the submission of (1) a signed and approved contract with Boston Edison Company for 132 MW ("RFP 3") or (2) signed and approved power purchase agreements which include capacity payments for at least 75 percent of the proposed project's electric output, would be sufficient evidence to establish that the proposed project would provide a necessary energy supply for the Commonwealth. Id. at 106.

With respect to viability, the Siting Board found that, upon the submission of signed and approved PPAs with Boston Edison Company for 132 MW or signed and approved PPAs for at least 75 percent of the proposed project's electric output, Altresco would have established that its proposed project is financiable. Id. at 141-142. The Siting Board also found that upon compliance with the condition that the Company provide the Siting Board with a signed copy of an agreement between Altresco and the Lynn Water and Sewer Commission for provision of treated effluent and potable water, Altresco would have established that its proposed project is likely to be constructed within applicable time frames and be capable of meeting performance objectives. Id. at 144. Accordingly, the Siting Board found that, upon compliance with these conditions, Altresco would establish that its proposed project is likely to be a viable source of energy.

of the Altresco project on the submission of signed and approved power purchase agreements ("PPAs") to demonstrate a year of need earlier than 2000. Point of Pines and Revere argued that the Siting Board precluded any factual inquiry into whether such PPAs would, in fact, be evidence of need or of a supply of energy at the lowest possible cost (Joint Petition for Appeal at 5). Point of Pines and Revere also argued that the Siting Board's need determination was not based on an independent and case-specific evaluation of evidence in the record (id. at 8). Point of Pines and Revere asserted that, by relying on the mere existence of a Boston Edison Company ("BECo") PPA without conducting an inquiry into the circumstances of that contract's creation, the Siting Board's approval of the Altresco petition was not supported by substantial evidence (id. at 16). Point of Pines and Revere interpreted the Siting Board's decision to condition approval on the submission of signed and approved PPAs as a failure to find a need for the proposed project (id. at 8, 9, 19).

As a second set of issues, Point of Pines and Revere argued that the Siting Board improperly found that the proposed facility will provide power at the lowest possible cost. Specifically, Point of Pines and Revere argued that the Siting Board's comparative cost analysis erroneously excluded consideration of the costs of (a) the alternative of implementing demand side management ("DSM") energy savings and conservation techniques, and (b) the alternative of purchasing excess power supplies from the New England Power Pool ("NEPOOL") energy grid (id. at 17-18). Point of Pines and Revere also asserted that the Siting Board failed to determine that the proposed project would offer power at a cost below purchasing utilities' avoided costs (id.).

As noted above, the Court issued its decision in Point of Pines v. Siting Board on January 11, 1995. The Court remanded the case to the single justice with instructions that the Siting Board decision conditionally approving the siting of the Altresco facility be vacated, and stated that "[w]e leave any question concerning a reopening of the [Siting B]oard's hearings to the discretion of the [Siting B]oard." Point of Pines v. Siting Board, 419 Mass. at 287.

Addressing the Siting Board's conditional approval of the proposed Altresco project, the Court stated that the Siting Board had not explained how the approval of PPAs by the

Department, which may show need for an individual utility, implies a need for the Commonwealth. Id. at 284-285. The Court noted that it had not received a reasoned explanation of the inferability of Commonwealth need from utility need in either this case, arguments before the Court concerning this case, or in previously cited Siting Board decisions. Id. Further, the Court noted that the Siting Board may not abdicate its independent responsibility to ensure that projects are necessary by relying solely on conclusions of the Department, and stated that the Siting Board must make an independent finding of Commonwealth need before approving the construction of a new facility. Id. at 286.

The Siting Board will comply with the Court's directive relative to making an independent finding regarding the need for Altresco's proposed project in Section II.B, below. Before doing so, however, the Siting Board notes that the Court's decision in Point of Pines v. Siting Board did not address several other issues which were raised on appeal. Our analysis in this decision will rely in part on portions of the Altresco Decision which were not addressed by the Court. Therefore, we find it necessary to address herein the misunderstandings or misinterpretations of the parties reflected in those other issues which were raised on appeal, in order to clarify the basis for, and the subsidiary findings of, this decision and the Altresco Decision.

As to the first set of issues raised on appeal, stemming from the use of signed and approved PPAs as evidence of need earlier than the year 2000, the Siting Board acknowledges that it did not properly justify the use of such PPAs in the Altresco Decision. Further, the Siting Board will neither place any reliance on such PPAs as evidence of need in this decision, nor place any condition on Altresco that requires the submission of PPAs for such purpose in the future. Accordingly, all arguments with regard to this issue are moot. In regard to Point of Pines' and Revere's assertion as to the Siting Board's failure to find a need for the proposed project, the Siting Board will address this in Sections II.B.2 and II.B.3, below.

With regard to the second set of issues raised on appeal regarding the comparative cost analysis excluding consideration of DSM[5] and conservation as alternatives to the proposed facility, in essence, Point of Pines and Revere urged the Siting Board to ignore the plain language of its statute and Court decisions that indicate the proper tools for use in statutory interpretation.[6] The Siting Board has previously considered and rejected similar arguments in Eastern Energy Corporation, EFSB 90-100R2, 7-9 (1995) ("EEC Decision III"). In considering whether conservation or conservation and load management should be

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5 Demand side management or DSM encompasses both conservation and load management measures. Conservation is a technology, measure, or action designed to decrease the kilowatt or kilowatthour requirements of an electric end-use, thereby reducing the overall need for electricity. Eastern Energy Corporation (on remand), 1 DOMSB 213, n. 94 (1993). Load management, on the other hand, is a measure or action designed to modify the time pattern of customer electricity requirements, for the purpose of improving the efficiency of an electric company's operating system. Id. For example, a utility may reach an agreement with a manufacturer that uses electricity whereby that manufacturer will curtail its use during peak times when the utility's system, as a whole, is placing increasing demands for electricity for cooling or heating purposes. During non-peak times the manufacturer may then resume its use of electricity. The utility providing electricity has, therefore, managed its load, thereby decreasing its need for additional peak capacity. Id.

The Siting Board notes that its statute requires consideration of both "load management" and "conservation and load management" as explained in the ensuing text. Accordingly, the Siting Board's discussion of DSM reflects this statutory distinction.

6 The Court has held that, in construing a statute, common words and phrases employed in the statute are to be accorded their usual meaning. Commissioner of Corp. & Tax v. Chilton Club, 318 Mass. 285, 288-289 (1945); citing, Fluet v. McCabe, 299 Mass. 173 (1938); Hinckley v. Retirement Board of Gloucester, 316 Mass. 496 (1944), and Killiam v. March, 316 Mass. 646 (1944). In addition, statutory language, when clear and unambiguous, must be given its ordinary meaning. Bronstein v. Prudential Ins. Co. of America, 390 Mass. 701, 704 (1984); Hashimi v. Kalil, 388 Mass. 607, 610 (1983). Further, none of the words of a statute is to be disregarded, for they are the main source for the ascertainment of the legislative purpose. Commissioner of Corp. & Tax v. Chilton Club, supra, at 288; Nichols v. Commissioner of Corporations & Taxation, 314 Mass. 285 (1943). And, "no word in a statute is to be treated as superfluous, unless no other possible course is open." Commonwealth v. McMenimon, 295 Mass. 467, 469 (1936).

analyzed as alternatives to a proposed project, "[t]he starting point of our analysis is the language of the statute, 'the principal source of insight into Legislative purpose.' Commonwealth v. Lightfoot, 391 Mass. 718, 720 (1984)." City of New Bedford, 413 Mass. at 484, citing, Simon v. State Examiners of Electricians, 395 Mass. 238, 242 (1985).

Specifically, G.L. c. 164, § 69J states that:

> [a] petition to construct a facility shall include ... the following information: a description of actions planned to be taken by the applicant to meet future needs or requirements, including, but not limited to ... a description of alternatives to planned action such as ... no additional electrical power or gas; a reduction of requirements through load management ... (emphasis added).

Additional requirements of Section 69J include that:

> [t]he [Siting B]oard shall ... approve a petition to construct a facility ... if it determines that it meets the following requirements: ... projections of the demand for electric power, or gas requirements and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods and include an adequate consideration of conservation and load management ... (emphasis added).

Based on the ordinary meaning of the words of Section 69J, the Legislature has directed the Siting Board to include consideration of "conservation and load management" ("C&LM") in its projections of the demand for electric power. Had the Legislature meant "conservation" also to be included as one of the alternatives to a petitioner's planned action, the Siting Board presumes the Legislature would have so stated. To assume that the Legislature intended the term "no additional electrical power,"[7] which is included in the list of alternatives, to mean the same as "conservation," when it had used this latter term elsewhere in the same statute, would result in the Siting Board ignoring the plain meaning of the words that were used and disregarding other words in the statute. Therefore, the Siting Board declines to accept the arguments of Point of Pines and Revere that would have the Siting Board ignore the intent of the Legislature as ascertained by the Legislature's choice of words.

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7 The Siting Board more fully addressed the meaning of the words "no additional electrical power" in the context of its statute in Eastern Energy Corporation (on remand), 1 DOMSB 213, 286-288 (1993).

Similarly, Point of Pines and Revere would have the Siting Board ignore that (1) the language of the statute requires the consideration of different DSM measures, i.e., "conservation" and "load management," in different ways, and (2) the term "load management" as used in the relevant statutory language modifies the phrase "description of actions planned to be taken by the applicant to meet future needs and requirements" and is not included in the clause that lists "a description of alternatives to such action." G.L. c. 164, § 69J. In City of New Bedford, 413 Mass. at 487-488, the Court faulted the Siting Council for failing to undertake a comparison of alternatives, a requirement that was clear from the language of the statute and identified by the Court in that decision. Where as here, the language of the statute is clear, and the rules of statutory interpretation prevent us from ignoring the plain language or treating it as superfluous, the Siting Board has refused to adopt the arguments of Point of Pines and Revere to do otherwise.[8,9]

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8 In addition, the Siting Board's interpretation of the language of its statute is consistent with an attempt to read the statute in a manner that will make sense of the legislative enactment. The Siting Board requires a developer to "include an adequate consideration of" C&LM in its projections of the demand for power by requiring the inclusion of all cost-effective C&LM measures, based on reasonable statistical projections. Projections of future demand are then reduced by the identified amount that can be attributed to such C&LM to establish the level of future need. As all cost-effective C&LM has been assumed to be implemented, no additional cost-effective C&LM measures would be available as an alternative to the planned action.

9 The Siting Board also notes that, as the Court indicated in City of New Bedford, prior to the review of Altresco's proposed facility in the Altresco Decision, the Siting Council "had required a non-utility applicant to establish that its proposed project was superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need for energy. This past practice comports with the [Siting C]ouncil's statutory mandate." 413 Mass. at 482. These past comparisons, for the reasons cited above, did not include a comparison of conservation as an alternative. Rather, conservation was analyzed in these earlier cases as required by the statute by adequately considering C&LM in the projections of the demand for electric power. The Siting Board can find no basis for abandoning a practice that is consistent with the language of its statute and that has been specifically acknowledged by the Court to comport with the statutory mandate.

With respect to the argument raised by Point of Pines and Revere that the Siting Board erred by failing to compare the cost of the Altresco project to the cost of purchasing excess power supplies through NEPOOL, the Siting Board notes that NEPOOL is simply a pooling arrangement for New England electric utilities which facilitates efficient generation planning and dispatch through the interchange of electric power among its member utilities. G.L. c. 164A, § 3. NEPOOL is not an independent source of power and, therefore, does not provide an alternative energy supply which would require separate analysis under G.L. c. 164, § 69J. Moreover, the Siting Board's analysis of regional need effectively considered whether excess supplies would be available from other New England electric utilities as part of its analysis of regional need, and concluded that no such regional surplus would be available to meet Massachusetts need beginning in the year 2000. As with C&LM, the potential availability of a NEPOOL (or New England utility) surplus is effectively eliminated by the Siting Board's finding of need for the Altresco project beginning in the year 2000 (Id., 2 DOMSB at 106), which means that no such surplus would exist in that year or beyond. There is no rational basis for requiring a cost comparison between the proposed facility and power supplies that will not exist.

In response to Point of Pines' and Revere's argument that the Siting Board failed to determine that the proposed Altresco facility offers power at a cost below purchasing utilities' avoided costs, the Siting Board notes that the parties are simply incorrect. In the previous decision in this proceeding, the Siting Board specifically found that the proposed Altresco project is likely to offer power at a cost below the purchasing utilities' avoided cost. Altresco Decision, 2 DOMSB at 131. This finding was based on a record indicating that the Altresco project could provide power at a cost below seven Massachusetts utilities' avoided costs.

C. Post-Appeal Procedural History

As noted above, the Court left to the discretion of the Siting Board whether to reopen hearings. Point of Pines v. Siting Board, 419 Mass. at 287. Thus the Siting Board must first determine whether it is necessary to reopen hearings to respond to the Court's directive.

In order to make such a determination, the Siting Board must review the existing record and determine whether the evidence contained therein is sufficient for a response to the Court, and if it is sufficient, whether the evidence remains valid. Finally, if the record evidence is sufficient and valid, the Siting Board must determine whether other factors might require the Siting Board to exercise its discretion and reopen hearings.

The Siting Board notes that it has before it both Altresco's pending petition and an extensive evidentiary record that was developed over more than two years by all parties to the proceeding. In order to make the above-noted determinations and move the proceeding toward closure, the Hearing Officer issued a memorandum on February 2, 1995 ("Memorandum") that provided all parties to the proceeding with an opportunity to address the issue of the reopening of hearings. In it, the Hearing Officer asked parties "to address the continued validity/sufficiency of the [existing] record evidence for the purpose of responding to the Court's directive" in Point of Pines v. Siting Board (Memorandum at 2). The Memorandum established a procedure that provided all parties with the opportunity to "make an Offer of Proof, as to specific additional information which should be included in the record to enable the Siting Board to decide those issues relevant to the Court's directive" (id.). The information to be submitted by the parties was to indicate the nature of the evidence (e.g., testamentary, documentary, etc.) that would constitute the Offer of Proof, the expectations of the movant as to what issues would be addressed and what would be demonstrated if such evidence were introduced, and the reasons why such evidence was not available at the time of the earlier development of the administrative record in the proceeding (id.). Further, all parties were provided an opportunity to submit a rebuttal to any Offer of Proof that was submitted (id.).[10]

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10 The Memorandum did not require the parties to submit additional record evidence. Rather, it asked the parties to indicate whether the existing record remained valid and sufficient to enable the Siting Board to respond to the Court's directive (Memorandum at 2). Further, if any party believed the record was not valid or sufficient, he was directed to identify specifically the additional information which the Board should consider, explain what that information would demonstrate, and explain why it was not previously available (id.). The Hearing Officer requested this information to assist (continued...)

The following two Offers of Proof were submitted: (1) February 24, 1995 Offer of Proof of the Point of Pines Beach Association ("Point of Pines Offer of Proof"); and (2) February 24, 1995 Filing of Altresco Lynn, Inc. in Response to the Hearing Officer's Memorandum ("Altresco Offer of Proof"). In addition, the following two rebuttals were submitted: (1) March 6, 1995 Response to Offer of Proof of Altresco Lynn, Inc. ("Point of Pines Rebuttal"); (2) March 6, 1995 Filing of Altresco Lynn in Response to Hearing Officer's Memorandum ("Altresco Rebuttal").[11]

1. The Parties' Offers of Proof

Point of Pines argued that the record should not be reopened, asserting that "[a]fter consideration of a voluminous record", the Siting Board found that the record evidence before it did not permit a conclusion that the proposed facility would provide a necessary

[10](...continued)
him in determining whether it was necessary to reopen hearings to take additional evidence in order to respond to the Court's concerns. However, parties were under no obligation to provide the Hearing Officer with such assistance (id.). The submissions that were made addressed the Hearing Officer's request to varying degrees and in varying ways, but for purposes of further discussion, all submissions will be referenced as Offers of Proof or Rebuttals as envisioned by the Memorandum.

[11] On February 9, 1995, BECo filed a petition for leave to intervene in this proceeding or, in the alternative, to participate as an interested person for the purpose of presentation of arguments and briefs. In a Hearing Officer Memorandum issued on April 11, 1995 ("Hearing Officer Memorandum of April 11, 1995"), the Hearing Officer noted that ample opportunity had been afforded the public to intervene in this proceeding, which commenced in March 1991, and accordingly found that BECo's petition constituted a petition for leave to intervene out-of-time (Hearing Officer Memorandum of April 11, 1995, at 4). The Hearing Officer also noted that this proceeding was not the appropriate forum in which to adjudicate BECo's need for power from the Altresco facility, and concluded that BECo had not shown that it was substantially and specifically affected by this proceeding (id.). Therefore, the Hearing Officer found no compelling reason for allowing BECo's untimely petition, and denied BECo's petition for leave to intervene or, in the alternative, to participate as an interested person (id., at 4-5). BECo submitted a conditional Offer of Proof on February 24, 1995. However, in light of the above ruling, the Siting Board does not consider it here.

energy supply for the Commonwealth (Point of Pines Offer of Proof at 1). Point of Pines argued that, since the Court struck down the use of PPAs as evidence of need, the Siting Board must now rely on its original findings and deny the petition to construct the proposed facility (id. at 1-2). However, Point of Pines asserted that if the petitioner filed an amended or new application, the entire record must be reopened (id. at 2).

Without waiving its objections to reopening the record, Point of Pines outlined information that should be evaluated if the record were reopened (id. at 2). With regard to the issue of need, Point of Pines stated that need projections in the 1994 NEPOOL Forecast Reports of Capacity, Energy, Loads and Transmission ("1994 CELT Report"), 1994 NEPOOL Resource Adequacy Assessment ("1994 Resource Assessment") and Boston Edison Company's 1994 IRM Filing ("1994 BECo IRM Filing") should be analyzed, and asserted that these documents would demonstrate that the Altresco facility would not be needed until well into the 21st century (id.).

Finally, Point of Pines argued that, "[i]f the Siting Board reopens the record, it should also ensure that a PPA based on RFP #3 or any other PPA plays no role in demonstrating need, nor provides any support in any way in favor of siting the proposed facility" (id.).

Altresco argued that the record should not be re-opened and asserted that the existing record is sufficient to support a decision to approve the proposed facility (Altresco Offer of Proof at 1). Altresco stated that the Court's decision found fault only with the Siting Board's new "market-based test" of need, which required the submission of signed and approved PPAs to demonstrate need (id. at 3). The Company argued that the Siting Board has already made the necessary independent finding of need required to approve the facility, in as much as the Siting Board has determined that Altresco will provide a necessary energy supply for the Commonwealth beginning in the year 2000 (id. at 5).

The Company stated that, due to delays in the construction schedule for the proposed facility arising from litigation, the in-service date of the project would be pushed back until 1998 or 1999 (id. at 7). Altresco cited record evidence indicating that it would need 30 months for further permitting and construction following financial closing, which would not occur until some time after Siting Board approval of the proposed facility (id. at 8, citing, Exh. HO-V-1). The Company noted that as Siting Board approval could occur no earlier than the summer of 1995, the earliest possible on-line date for Altresco's proposed project would be February 1998, assuming that financial closing was contemporaneous with Siting Board approval, a logistically unlikely result (id. at 7-9). Altresco also noted that the Siting Board has found that it is appropriate to consider the need for a project beyond the first year of operation, and that examining a four-year window of need is appropriate to reflect the uncertainties of resource planning (id. at 6). Therefore, the Company concluded that the Siting Board's finding of need for the year 2000 is sufficient to approve the proposed facility (id. at 7).

Altresco argued that the Siting Board could also make a finding of need for at least 170 MW of additional capacity before the year 2000 based on the current record and a reconsideration of policy decisions the Siting Board made at its October 1993 public hearing during consideration of the October 4, 1993 Tentative Decision in the matter of Eastern Energy Corporation (on remand) ("EEC (remand) Tentative Decision") (id. at 9). The Company asserted that overwhelming evidence could support a conclusion based on the methodology used in the EEC (remand) Tentative Decision, that the Altresco facility would be needed in the Commonwealth beginning in 1999, even after applying identified regional surpluses in that year (id. at 9-10). The Company further argued that it would be appropriate to adopt the staff methodology and analyses utilized in the EEC (remand) Tentative Decision, noting that the methodology used in the EEC (remand) Tentative Decision was set aside by the Siting Board in order to accommodate a finding of need conditioned on PPAs (id. at 11). Altresco argued that a return to that methodology would be appropriate in this proceeding following the Court's rejection of such reliance on PPAs in Point of Pines v. Siting Board (id.).

Finally, Altresco asserted that the submission of new evidence would only reinforce the previous findings of the Siting Board and would accelerate the year of need (id. at 14). In support of its assertion, the Company provided information in the form of an affidavit prepared by Robert Graham, of La Capra Associates ("Graham affidavit") that it would submit as evidence if hearings were reopened (id., Attachment B). The Graham affidavit purports to show an earlier year of need based on analyses of recent CELT Reports (id. at 14-15).

2. The Parties' Rebuttals

In response to Altresco's Offer of Proof, Point of Pines agreed with Altresco's position that the record should not be reopened, but argued that the Siting Board should deny the Company's petition (Point of Pines Rebuttal at 1). Point of Pines asserted that its legal rights would be abused if the issue of need were reexamined (id.). Point of Pines also stated that "[t]here was no error in the record as of December 15, 1993", the date on which the Altresco Decision was issued (id.). Point of Pines asserted that the Siting Board, in the Altresco Decision, accepted Point of Pines' position that the Altresco facility was not needed, and therefore improperly relied on the submission of PPAs to show need for the proposed facility (id.). Point of Pines argued that the Siting Board could and should reissue the Altresco Decision without the condition relating to PPAs (id.).

Point of Pines also argued that if Altresco changed its on-line date, it should be required to amend its petition, and the Siting Board should re-open the entire record (id. at 2). Point of Pines also argued that, if the record were reopened on the issue of need, the issues of alternative technologies, environmental impacts, and site selection should also be reexamined (id.). Specifically, Point of Pines asserted that progress in the development of Best Available Control Technology ("BACT") and alternative sources of energy had rendered the record in the Altresco Decision obsolete (id.).

Point of Pines also challenged Altresco's calculations in its Offer of Proof concerning the regional surplus (id.). Further, Point of Pines took issue with many of the conclusions and methodologies contained in the Graham affidavit (id. at 3). Point of Pines argued that a new need analysis, such as that submitted in the Altresco Offer of Proof, should be considered only in a reopened proceeding, where the intervenors would have the opportunity to rebut the evidence submitted (id. at 3).

Finally, Point of Pines asserted that "RFP #3 is the main source for the sale of the plant's energy" (id. at 4). Therefore, Point of Pines claimed that "[e]ven if the RFP #3 PPA is not used to show need for the facility, it must be examined to make a determination as to whether any siting of the facility will be consistent with the statutory policies" (id. at 7).

Altresco urged the Siting Board to reject Point of Pines' Offer of Proof due to Point of Pines' vague and unsubstantiated assertions concerning the need for new energy resources (Altresco Rebuttal at 3). Altresco asserted that Point of Pines' characterization of the Siting Board's Final Decision as finding need based solely on signed PPAs was flawed, and did not recognize that the record evidence included forecasts of future Commonwealth and New England energy requirements (id. at 1-2). Altresco argued that in the Altresco Decision the Siting Board made findings that support an independent determination that the proposed Altresco facility constitutes a necessary energy supply for the Commonwealth (id. at 2).

In response to Point of Pines' contention that if the record were reopened, the 1994 CELT Report and the 1994 BECo IRM filing should be examined, Altresco stated that Point of Pines did not identify how these documents address the need for new energy facilities, or their impact on the analyses and findings of the Altresco Decision (id. at 2-3). The Company further argued that the 1994 BECo IRM filing was not relevant to the need for new energy resources within the Commonwealth, and therefore did not constitute a basis for reopening the record (id. at 3-4).

Finally, the Company provided a second affidavit from Mr. Graham, that it would submit if the record were reopened, which concluded that load growth would increase and require the addition of new capacity before the year 2000 (id.).

3. Analysis

An analysis of the issues and arguments provided in the Offers of Proof and Rebuttals must commence with a review of the Court's decision in Point of Pines v. Siting Board, specifically with regard to the scope of the Court's directive to the Siting Board. In that decision, the Court noted that, in the course of the Altresco proceedings, the Siting Board "concluded that 'based on the record, the [Siting B]oard is unable to determine that the proposed project is needed to provide a necessary energy supply for the Commonwealth prior to the year 2000.'" Point of Pines v. Siting Board, 419 Mass. at 284. The Court continued, stating that

> "Even apart from the statutory requirement that the board make an independent finding of Commonwealth need as a prerequisite to approving construction of a facility, the [Siting B]oard's approval in this case must be set aside because, standing alone, the [D]epartment's approval of a [PPA] does not warrant an inference of Commonwealth need."

Id. at 286. As noted above, the Court then left to the Siting Board's discretion any question concerning reopening of hearings on this matter. Id. at 287. Thus, the Court vacated the Siting Board's decision due to the lack of a single finding and the improper or unexplained substitution of a proxy for that finding. Accordingly, the Siting Board finds that the scope of the Court's directive in Point of Pines v. Siting Board is very specific and is limited to the requirement that the Siting Board make an independent finding of need and not rely on signed and approved PPAs to take the place of such a finding.

The Court did not indicate that this necessary finding could not be made on the existing record. Rather, the Court acknowledged that the record in the Altresco proceeding contained voluminous material regarding capacity and demand forecasts for the Commonwealth and for New England. Id. at 283-284. Further the Court authorized the Siting Board to use its discretion in determining whether this record needed to be reopened. Therefore, the Siting Board finds that it must determine whether the existing record evidence on which its findings of need are based remains valid and sufficient to address the Court's directive. In order to assist him in determining whether the record evidence remained valid and sufficient, or whether the record needed to be reopened, the Hearing Officer requested that the parties submit Offers of Proof and Rebuttals in this proceeding.[12] Here the Siting

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[12] As stated in n.10, above, the Hearing Officer's request for Offers of Proof was not a request that parties enter new evidence into the record. Rather, the Hearing Officer's request was to identify evidence that would justify a finding by the Siting Board as to the continued validity and sufficiency of the existing record such that the Siting Board could respond to the Court's directive. Such an offer of proof is comparable to an offer of proof made during a judicial proceeding that would identify evidence to allow the presiding officer or appeals court to make a determination as to whether that (continued...)

Board reviews those Offers of Proof and Rebuttals, mindful that, although presented with several other issues on appeal, the Court's only stated concern with the Altresco Decision was with the lack of an independent finding of need and the use of PPAs to infer Commonwealth need.[13] First, however, in light of various arguments raised by the parties that would limit the Siting Board's options in this proceeding, the Siting Board must address what is meant by the term "discretion" as used by the Court.

A look at pertinent case law establishes that when discretion is exercised, it cannot lead to arbitrary action, but it also cannot lead to actions based on decisions made in a vacuum. Discretion implies flexibility and requires judgment based on consideration of all facts surrounding a situation. The Court has held that the term discretion when used in a statute denotes "freedom to act according to honest judgment." Paquette v. Fall River, 278 Mass. 172, 174 (1932); Corrigan v. School Committee of New Bedford, 250 Mass. 334, 339 (1924). In Paquette, the Court noted a United States Supreme Court decision that stated "The term *discretion* implies the absence of a hard-and-fast rule. The establishment of a clearly defined rule of action would be the end of *discretion*, and yet discretion should not be a word for arbitrary will or inconsiderate action. 'Discretion means a decision of what is just and proper in the circumstances.'" Paquette, above, 278 Mass. at 174, citing, The Styria v. Morgan, 186 U.S. 1, 9 (1902). The Siting Board, therefore, must carefully consider the circumstances surrounding this proceeding. Further, the history surrounding the enactment

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[12](...continued)
information should be allowed into the record of the judicial proceeding.

The Siting Board notes that any evidence submitted with the Offers of Proof would become a part of the record in this proceeding to be considered by the Hearing Officer and staff in the preparation of a tentative decision if, and only if, a finding were made that it was necessary to reopen the record. The Siting Board acknowledges that such a finding would then result in the evidence submitted being subject to discovery, cross-examination, and rebuttal as per the requirements of G.L. c. 30A, § 11.

[13] While the Court did not address the issue of viability, the financiability portion of the viability finding in the Altresco Decision included a condition requiring the submission by the Company of signed and approved PPAs for the Altresco facility. The Siting Board addresses this issue in Section II.C, below.

of our statute provides additional circumstances that must be considered.[14] The Siting Board must then use honest judgment as to what is just and proper in deciding whether to reopen hearings. Thus, in determining whether to exercise its discretion, the Siting Board must consider (1) the specifics of the Court's directive in Point of Pines v. Siting Board, i.e., to make an independent finding of need, (2) the historical context of the Siting Board's statutory mandate, and (3) the state of the existing record.

With regard to the historical context of the Siting Board's statutory mandate, the Siting Board notes that it and its predecessor agency, the Siting Council, were empowered to oversee a process whereby the Commonwealth's future energy needs would be identified early enough so that plans to meet those needs could be approved, and actions to meet those future needs could be taken. The parties to this proceeding may differ as to the extent and timing of future need, but if projections of need are subject to continued evaluation, timely action to meet those future needs may be prevented. Such possibilities were seen by the Legislature when it first studied the problems associated with siting energy facilities.

The Massachusetts Electric Power Plant Siting Commission ("Siting Commission"), the commission responsible for the drafting of the initial siting legislation, was concerned that a collision of "contradictory public attitudes about electric power" could slow the orderly development of essential power supplies. Third Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6190, March 30, 1973 ("Third Report").[15] The Siting Commission sought to mitigate two factors it perceived as delaying new and needed capacity: insufficient public notice and environmental challenges. Id. at 8, 9, 15. The enactment of Sections 69G through 69J of G.L. Chapter 164 was aimed at addressing these two concerns. Id. at 15, 20.

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14 The Siting Board notes that the Court has held that: "[s]tatutes are to be interpreted, not alone according to their strict verbal meaning, but in connection with their development, their progression through the legislative body, the history of the times, [and] prior legislation ...." Wilcox v. Riverside Park Enterprises, Inc., 399 Mass. 533, 535 (1987), quoting, Commonwealth v. Welosky, 276 Mass. 398, 401 (1931).

15 A more complete analysis of the activities of the Siting Commission can be found in the EEC (remand) Decision, 1 DOMSB at 246-251.

To establish future need and ensure timely action to meet such need, G.L. c. 164, § 69I requires all electric companies to file long-range forecasts for the ensuing ten-year period with respect to the power needs and requirements of their market area. With respect to an electric utility that is required to file such forecasts, the Siting Board may approve a petition to construct a facility only if it is consistent with the company's most recently approved long-range forecast. G.L. c. 164, § 69J. Accordingly, after a Siting Board review, consistent with the requirements of G.L. c. 164, § 69J, an electric utility proposal to construct a facility could be approved up to ten years prior to its on-line date, assuming that the most recently approved long-range forecast for that utility indicated a need for the facility in that year. Thus, the siting statute envisioned the approval of facilities before a need for such facilities actually existed.

With respect to an electric company with no set market area, i.e., a non-utility developer, the Siting Board has required comparable long-range forecasts of power needs and requirements in conjunction with its petition for approval of a proposed facility. Thus, based on the historical context of the Siting Board's statutory mandate, the Siting Board concludes that approval of a non-utility developer's petition to construct a facility is appropriate if the Siting Board finds that the long-range forecasts demonstrate a need for the proposed facility.[16]

The Siting Board acknowledges that future need for electric power is dependent on numerous factors, any one of which, if altered, could affect the ultimate timing of need. Thus, the Siting Board now reviews the state of the existing record. As an initial matter, the Siting Board finds that its statute requires that projections of future need must be based on substantially accurate historical information and reasonable statistical projection methods. G.L. c. 164, §§ 69I & 69J. In the present proceeding, the Siting Board conducted an extensive analysis of need forecasts for the region and Massachusetts consistent with the

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16 In City of New Bedford, the Court acknowledged the Siting Council's argument "that the review format of the long-range forecast is not easily applied to a non-utility producer." 413 Mass. at 488. The Court stated that modifications to the procedure may be necessary to accommodate the non-utility producer but cautioned that any such modifications "must permit a review that fulfills the statutory mandate." Id.

statutory guidelines that are contained in G.L. c. 164, § 69J, and the Court's directive in City of New Bedford, above. Both Altresco and Point of Pines acknowledge that the record on need in the Altresco Decision was sufficient and complete. In fact, both parties in their Offers of Proof and their Rebuttals opposed reopening the record, arguing that the Siting Board should rest on the need findings in the existing record, although they disagreed as to whether those findings would compel the approval or rejection of the facility. The Siting Board thus finds that the existing record on both regional and Massachusetts need is extensive and provided sufficient evidence to support an independent finding regarding need at the time that the Altresco Decision was issued. Therefore, as the Siting Board has undertaken the analysis of need required under its statute and no party has identified any information that would lead the Siting Board to conclude that the record is insufficient to do so, the Siting Board also finds that the record evidence is sufficient to respond to the Court's directive. Accordingly, the Siting Board now looks to the continued validity of the record evidence.

Findings of future need that are based on such substantially accurate historical information and reasonable statistical projection methods are not rendered inaccurate or in violation of the statute simply with the passage of time. Consistent with its recent EEC Decision III, issued June 27, 1995, the Siting Board finds that in an ongoing proceeding such as this, it is only if evidence of a nature that would demonstrate that one or more factors that affect the historical information or statistical projection methods have significantly changed, that findings of future need based on such information or methods would be brought into question. The Siting Board here concludes that sufficient evidence to indicate that future projections are significantly changed must be identified before a record is reopened.

With regard specifically to the future demand for electricity, both Altresco and Point of Pines noted that if the record were reopened, the Siting Board should consider recent versions of the CELT report[17] that are not contained in the existing record. Since the Siting Board has concluded that the record should be reopened only if sufficient evidence has been

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17 For purposes of discussion, all references to CELT reports encompass all the related NEPOOL forecasts, including the NEPOOL Resource Adequacy Assessment.

identified that would indicate that projections of future need have significantly changed, we must consider whether the existence of later CELT reports constitutes such evidence. This requires a review of our consideration of those CELT reports that are present in the record.

The Siting Board notes that all the CELT reports that were previously admitted into the record have been subjected to numerous corrections, analyses and other manipulations by the parties to the proceeding. Thus, the information provided in the CELT reports amounts to a starting point for analysis, not a definitive statement as to future need. Indeed, if the CELT reports could serve that purpose, the Siting Board's independent finding of need, although it would still be required by the statute as the Court has indicated, would be superfluous. Our rejection, after a complete analysis, of the 1991 CELT Report (see, EEC Decision, 22 DOMSC at 235-236) illustrates that CELT reports are not to be treated any differently than any other piece of evidence that is submitted. Thus, the Siting Board has no independent basis to conclude that more recent CELT reports necessarily provide more accurate demand projections than earlier CELT reports.

Of those making Offers of Proof regarding the later CELT reports, only Altresco addressed the accuracy of those reports. However, Altresco's analysis, even if assumed to be accurate, fails to establish that an examination of more recent CELT reports is likely to result in a substantial change in the year of need.[18] Thus, no party's offer of proof provides clear reason for the Siting Board to reopen the record, based on any expectation that review of more recent CELT reports is likely to lead to a finding of substantially earlier or later need.

The Siting Board finds that no party has provided any support for its conclusion that the more recent CELT reports provide substantially different and more accurate information or demonstrate that those CELT reports currently in the record are invalid.[19] Accordingly,

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18 The Siting Board notes that, although Point of Pines claimed that more recent CELT reports would demonstrate no need for the Altresco facility until well into the 21st century, Point of Pines did not explain how these updated CELT reports would lead to such a conclusion.

19 The Siting Board is unable to conclude that a later report is necessarily more accurate based solely on its having been issued at a later time.

the Siting Board finds that it has no basis on which to conclude that the analyses of need based on those CELT reports that are currently in the existing record are no longer valid for purposes of supporting a finding of need. Further, the Siting Board has no basis on which to conclude that the more recent CELT reports, standing alone, would better enable it to respond to the Court's directive.

In addition to the 1994 CELT Report, Point of Pines argued that the Siting Board should consider both the 1994 BECo IRM filing and "the relation of RFP #3 to the needs of Boston Edison and the Commonwealth as a whole" in a reopened record on need. The Siting Board rejects this argument. In response to the Court's directives in Point of Pines v. Siting Board, the Siting Board here considers whether the proposed facility provides a necessary supply of energy to the Commonwealth, without reference to existing or potential PPAs between Altresco and any other party. This analysis is based, not on information from individual utilities' IRM filings, but rather on projections of the energy needs for the Commonwealth and the region as a whole. To paraphrase the Court's decision, Point of Pines has provided no reasoned explanation as to the inferability of Commonwealth need from BECo's need for power. See, Point of Pines v. Siting Board at 284-285.

Neither is there any reason for the Siting Board to take up the issue of BECo's RFP 3. The timing of Commonwealth need in the aggregate is not dependent upon and will not be affected by the disposition of the PPA between Altresco and BECo. Questions regarding the continuing appropriateness of the PPA are properly before the Department, and it would be improper for the Siting Board to comment upon them at this time. Consequently, the Siting Board finds that an examination of the BECo IRM filing and issues surrounding RFP 3 would be irrelevant to the determination of Commonwealth need, and therefore would not indicate that the Siting Board's analysis of need in the Altresco Decision is no longer valid.

Based on the above, the Siting Board finds that none of the parties has identified any potential evidence, as requested by the Hearing Officer, that would indicate that the Siting Board's analysis of need in the Altresco Decision is no longer valid or is based on insufficient evidence, such that we are compelled again to revisit the issue of need. In addition, the Siting Board finds that none of the parties has identified any other factors that would compel us to reopen the record. Further, the Siting Board finds that it does not have independent general, technical or scientific facts within its specialized knowledge, as permitted pursuant to G.L. c. 30A, § 11(5), which would lead it to determine that the existing record is invalid or insufficient.[20]

4. Findings and Conclusions

In Section I.C.3, above, the Siting Board has found that:

- the scope of the Court's directive in Point of Pines v. Siting Board is very specific and is limited to the requirement that the Siting Board make an independent finding of need and not rely on signed and approved PPAs to take the place of such a finding (p. 16);
- it must determine whether the existing record evidence on which its findings of need are based remains valid and sufficient to address the Court's directive (p. 16);
- its statute requires that projections of future need must be based on substantially accurate historical information and reasonable statistical projection methods, G.L. c. 164, §§ 69I & 69J (p. 19);
- the existing record on both regional and Massachusetts need is extensive and provided sufficient evidence to support an independent finding regarding need at the time that the Altresco Decision was issued (p. 20);
- the record evidence is sufficient to respond to the Court's directive (p. 20);

20 The Siting Board notes that during the period between the issuance of the Altresco Decision and this decision, the state and region did not undergo major changes in the economy. More importantly, no party has identified any evidence that would support a finding by the Siting Board that current economic conditions are substantially different than those that were used in the need projections in the Altresco Decision. Accordingly, the Siting Board has no basis on which to conclude that the introduction of new evidence on need would do any more than provide an opportunity to relitigate an issue that already has been resolved. (Compare Eastern Energy Corporation (on remand), above, where the Court's directive in City of New Bedford, above, required reconsideration of two issues for which a full record had not been developed, and where a major economic slowdown occurred during the period between EEC's initial filing and the Court's remand decision.)

- in an ongoing proceeding such as this, it is only if evidence of a nature that would demonstrate that one or more factors that affect the historical information or statistical projection methods have significantly changed that findings of future need based on such information or methods would be brought into question (p. 20);
- no party has provided any support for its conclusion that the more recent CELT reports provide substantially different and more accurate information or demonstrate that those CELT reports currently in the record are invalid (p. 21);
- it has no basis on which to conclude that the analyses of need based on those CELT reports that are currently in the existing record are no longer valid for purposes of supporting a finding of need (pp. 21-22);
- an examination of the BECo IRM filing and issues surrounding RFP 3 would be irrelevant to the determination of Commonwealth need, and therefore would not indicate that the Siting Board's analysis of need in the Altresco Decision is no longer valid (p. 22);
- none of the parties has identified any potential evidence, as requested by the Hearing Officer, that would indicate that the Siting Board's analysis of need in the Altresco Decision is no longer valid or is based on insufficient evidence, such that we are compelled again to revisit the issue of need (p. 22);
- none of the parties has identified any other factors that would compel us to reopen the record (pp. 22-23); and
- it does not have independent general, technical or scientific facts within its specialized knowledge, as permitted pursuant to G.L. c. 30A, § 11(5), which would lead it to determine that the existing record is invalid or insufficient (p. 23).

Accordingly, the Siting Board concludes that the existing record evidence on which its need analyses in the Altresco Decision were based remains valid and can serve as the basis for an independent finding of need in response to the Court's directive in Point of Pines v. Siting Board.

As the Offers of Proof and Rebuttals provided to the Siting Board fail to identify information that would lead the Siting Board to conclude that the existing record is either invalid or insufficient or that the need projections have significantly changed, the Siting Board will not, based on conjecture and supposition, reopen the record. The Siting Board concludes that to do so would be contrary to the Court's discussion in Paquette v. Fall River, above, in that it would amount to an arbitrary action that is not just and proper under the circumstances, and therefore would amount to an abuse of the discretion afforded the Siting Board by the Court.

In making such a determination, the Siting Board is mindful of the Legislature's concern, as expressed in the Third Report, that new and needed capacity could be delayed. The need to plan in advance for future requirements dictates a reasonable limitation on analysis and a move to action on that analysis at some point. Where, as here, the Court has identified one legal error in the Altresco Decision, the Siting Board concludes that it would be contrary to legislative intent to allow for a relitigation of issues that have already been extensively litigated.[21] Where no evidence has been identified by the parties that would lead the Siting Board to conclude that the existing record was insufficient to address, or no longer valid for addressing, the sole issue raised by the Court after affording all parties an

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21 Had no record been developed on the issue of need, the Siting Board would have been in a comparable position to the Department in the Court's recent decision in Boston Edison Company v. Department of Public Utilities, 419 Mass. 738 (1995) ("BECo vs. DPU") and would have needed to reopen the record. In that case, the Department found it unnecessary to reopen the record to consider an offer of proof on an issue that had not been reviewed, i.e., BECo's avoided costs in light of the deferral of its proposed generating plant. Id., 419 Mass. at 744, 746. In contrast, as the Court has recognized in this proceeding, the Siting Board has reviewed voluminous material regarding capacity and demand forecasts for the Commonwealth and for New England. As no party has identified information that would establish that the existing record was either insufficient (as in BECo vs. DPU) or no longer valid for purposes of reviewing future need and responding to the Court's concern in Point of Pines v. Siting Board, the Siting Board has exercised the discretion afforded it by the Court and decided that to reopen the record would not be just and proper under the circumstances surrounding this proceeding. See, Paquette v. Fall River, 278 Mass. at 172.

opportunity to do so, the Siting Board can find no reason to further delay these proceedings by reopening the record, and will address the Court's directive based on the existing record.[22]

Having determined that no evidence has been identified by the parties that would lead the Siting Board to conclude that the existing record is either invalid or insufficient to respond to the Court's directive in Point of Pines v. Siting Board, and having no independent basis on which to make such a determination, the Siting Board will consider the existing record in making its independent determination as to the need for Altresco's proposed facility. The remaining issues raised by the parties in their Offers of Proof and Rebuttals will be addressed in Sections II.B. and II.C., below. Before doing so, however, the Siting Board must revisit its findings in the Altresco Decision that have been affected by the Court's decision.

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22 The Siting Board notes that its decision not to reopen the record in this case is consistent with actions it has taken in prior cases, including its decision in the Eastern Energy Corporation proceedings to reopen the record on the five issues identified by the Court in City of New Bedford, above. See Section I.A. and n.3, above. As noted above, the Court's directive is significantly more limited in scope in Point of Pines v. Siting Board than in City of New Bedford. Further, the record developed in the EEC Decision was neither sufficient nor valid for purposes of responding to the Court's directive in City of New Bedford. The Court's directive in that decision required reconsideration of two issues for which a full record had not been developed in the record on which the EEC Decision was based, i.e., the comparison of alternative resources and the analysis of Massachusetts need. In addition, new evidence of need was appropriate due to the major economic slowdown during the period between EEC's initial filing and the remand proceedings in that case (see EEC Decision III, EFSB 90-100R2, at n.33). In contrast, a sufficient record has been developed in the Altresco proceedings to address the Court's one stated concern in Point of Pines v. Siting Board. Further, no party has identified any information that would support a finding by the Siting Board that current economic conditions are markedly different than those used in the need projections in the Altresco Decision.

II. ANALYSIS OF THE PROJECT[23]

A. The Final Decision in EFSB 91-102

1. Identification of Affected Findings

The following excerpts from the Altresco Decision constitute the Siting Board's requirements of Altresco relative to the submission of PPAs. In that decision, the Siting Board relied upon PPAs to demonstrate the proposed project's viability, as well as the need for the project. In Point of Pines v. Siting Board the Court did not address the Board's reliance on PPAs in its analysis of viability. However, as the Siting Board will no longer rely on PPAs in its determination of need, the Siting Board, as a separate matter, reexamines, in Section II.C, below, its use of PPAs as they relate to the proposed project's viability.

In response to the Court's directive in Point of Pines v. Siting Board, the Siting Board hereby rescinds the conditions relating to PPAs and amends its Altresco Decision by deleting from it the following language:

- Here, in light of the need for the proposed project beginning in the year 2000 on reliability grounds, the Siting Board finds that the 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. Altresco Decision, 2 DOMSB at 106.

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23 In determining whether a proposed project will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board conducts a broad analysis addressing a number of specific issues: (1) need for additional energy; (2) alternative project technologies; (3) project viability; (4) site selection; (5) facility environmental impacts; (6) facility costs, and (7) facility reliability. In this proceeding, as discussed in Section I.A, above, the Siting Board issued the Altresco Decision, which addressed these issues.

- 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' [sic] 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. Id., 2 DOMSB at 141-142.

- 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. Id., 2 DOMSB at 144.

- 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. Id., 2 DOMSB at 161.

- 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 PPAs. Id., 2 DOMSB at 161-162.

- 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. Id., 2 DOMSC at 222.

2. Status of Remaining Findings

In Point of Pines v. Siting Board, although presented with several issues on appeal, the Court faulted the Siting Board only for its failure to make an independent finding of need and its reliance on PPAs in place thereof and did not identify any other issues of concern. The Court also did not disturb any of the subsidiary findings in the Altresco Decision except as they relate to the issue of the independent finding of need and the reliance on PPAs.

The findings in the Altresco Decision, beyond those identified in Section II.A.1, above, are based on the record evidence, which the Siting Board has concluded in Sections I.C.3 and I.C.4, above, to be sufficient and valid. Accordingly, the Siting Board reaffirms all of the other findings, conditions, and recommendations in the Altresco Decision and hereby incorporates them by reference.[24]

B. Need Analysis

1. Introduction

As discussed in Sections II.A.1 and II.A.2, above, the Court's decision in Point of Pines v. Siting Board was limited to the findings and conditions associated with the need for the proposed facility. Specifically, the Court's decision addressed the conditions pertaining to the reliance on signed and approved PPAs. In the following section we review our findings on the issue of need for Altresco's proposed project.

2. The Commonwealth's Need for Additional Energy Resources

In response to the Court's directive in City of New Bedford, the Siting Board set forth the following standard of review for evaluating need for non-utility developers which it used in its evaluation of need in the Altresco Decision:[25]

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24 The Siting Board has included the findings relative to the issue of need from the Altresco Decision in Appendix A to this decision.

25 The Siting Board notes that this standard of review would be identical for an electric (continued...)

> 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.

Cabot Power Corporation, 2 DOMSB 241, 259 (1994) ("Cabot Power Decision"); EEC (remand) Decision, 1 DOMSB at 423.

Therefore, in order to evaluate the need for the proposed project on reliability grounds, the Siting Board in this proceeding reviewed forecasts of demand and supply for both the New England region and the Commonwealth. Altresco Decision, 2 DOMSB at 30-57, 70-88. The Siting Board review, with respect to the demand forecasts, focussed on demand forecast methodologies and estimates of DSM savings over the forecast period. Id. With respect to the supply forecasts, the Siting Board review included a review of capacity assumptions, contingency adjustments, and required reserve margin assumptions. Id. The Siting Board then reviewed forecasts of need, which are based on a comparison of the various demand and supply forecasts. Id., 2 DOMSB at 57-61, 88-92. Thereafter, the Siting Board reviewed how transmission and air quality benefits affected need. Id., 2 DOMSB at 92-102. The Siting Board also considered the need for the proposed project on grounds of economic efficiency savings, including (1) the variable cost savings resulting from inclusion of the proposed project in the NEPOOL dispatch pool, and (2) the avoided cost of new capacity to meet identified regional need. Id., 2 DOMSB at 61-68.

Based on this extensive analysis, the Siting Board found that (1) New England will need 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

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[25](...continued)
utility proposing to construct a facility to meet a Commonwealth need as opposed to its own need. If such an electric utility were proposing to construct a facility to meet its own needs, the Siting Board would only need to review that utility's most recently approved long-range forecast. Thus, the Siting Board's need analyses for electric utilities and non-utility developers are comparable.

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. Id., 2 DOMSB at 161. Further, the Siting Board 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. Id., 2 DOMSB at 103.

The analysis by the Siting Board showed, however, that the record was 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. Id., 2 DOMSB at 104. Thus, the Siting Board concluded that there was insufficient evidence to determine that the proposed project would be needed to provide a necessary energy supply for the Commonwealth prior to the year 2000. Id. However, the Siting Board found 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. Id., 2 DOMSB at 103.

The Court has acknowledged that the record in the Altresco proceeding, which the Siting Board reviewed in reaching the conclusion that the proposed project was not needed to provide a necessary energy supply for the Commonwealth prior to the year 2000, contained voluminous material regarding capacity and demand forecasts for the Commonwealth and for New England. Point of Pines v. Siting Board, 419 Mass. at 283-284. The Court has not identified any legal flaw in the Altresco Decision other than its reliance on purchased power agreements to demonstrate need. Further, no party challenged the finding that the Commonwealth will have a need for an amount of capacity equal at least to that of Altresco's proposed facility in the year 2000 and beyond. Finally, in Section II.A.2, above, the Siting Board reaffirmed and incorporated herein all of the other findings, conditions, and recommendations in the Altresco Decision. Therefore, Point of Pines' assertion that the Siting Board could not conclude that the proposed project would provide a necessary energy supply for the Commonwealth is without merit.

Accordingly, the Siting Board finds that the existing record clearly establishes a need for reliability purposes in the Commonwealth in the year 2000 and beyond for an amount of capacity equal at least to that of Altresco's proposed facility.

The Siting Board must, therefore, determine whether Altresco's proposed facility will be available to meet that need in the year 2000. In the Altresco Decision, 2 DOMSB at 104, 125, the Company proposed an on-line date of 1996. Altresco introduced evidence in this proceeding that established that the construction of the proposed facility would take 30 months following financial closing. No party has challenged this evidence, and no party has identified any evidence that it would provide, were the record to be reopened, that is contrary to such a timetable for construction. At this time, if the final Siting Board approval is granted in August of 1995, the earliest possible date that Altresco's proposed facility could commence operation would be February, 1998. This assumes (1) financial closing contemporaneous with approval, and (2) no further judicial proceedings. As it is likely that financial closing will take a minimum of several months, and perhaps considerably longer, the Siting Board finds that Altresco's proposed facility would be capable of commencing operation no earlier than February, 1998, and probably not until the summer of 1998 or later.

As noted above, Point of Pines has argued that the Siting Board cannot recognize that the on-line date of the proposed facility has been changed without re-opening the record to consider alternative sources of energy, environmental impacts and site selection[26] using updated information, since there has been progress in the development of BACT and alternative sources of energy since these analyses were completed. The Siting Board rejects this argument for the following reasons.

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[26] While Point of Pines asserted that the site selection process should be reexamined, it did not give any reason for this assertion. The Siting Board notes that, unlike its analyses of need, alternative technologies and environmental impact, the site selection analysis addresses a purely historical and methodological issue, namely, whether Altresco considered a reasonable range of practical facility siting alternatives in selecting the Lynn site. Thus, the only grounds for reopening the record on the site selection process would be the availability of new and previously unavailable information regarding the Company's actions prior to its selection of the Altresco site.

With regard to changes in alternative sources of energy, no new evidence has been identified by any party that is likely to alter the Siting Board's finding 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. Altresco Decision, 2 DOMSB at 136. In addition, no party has identified any evidence that would lead the Siting Board to conclude that new technologies exist beyond those considered in that decision. Further, with regard to BACT development, the Siting Board notes that the nature of BACT is that it is constantly changing. In the present case, however, no party has identified any recent application of BACT that could be examined in a reopened record that would lead the Siting Board to revisit its finding that the environmental impacts of the proposed facility could be further minimized with respect to air quality consistent with minimizing cost.

The Siting Board also notes that its statute explicitly provides for the conditional approval of petitions to construct jurisdictional facilities. G.L. c. 164, § 69J. Such conditions may include prerequisites for establishing viability, as well as design or mitigation conditions related to minimizing environmental impacts. The Siting Board notes that, whenever it exercises its statutory authority to approve the construction of a facility subject to need or viability conditions, it accepts the continuing validity of those portions of its analysis upon which it does not place conditions. If facilities were repeatedly refused approval because a newer technology, which may have some marginal benefit over the facility under review, has been developed, needed power facilities could not be approved and constructed in a timely fashion. For this reason, the Siting Board establishes a deadline for compliance with the conditions of such approvals.

In the Altresco Decision, the Siting Board allowed the Company four years from the date of the conditional approval to submit signed and approved PPAs to establish the need for the proposed project. 2 DOMSB at 222. In doing so, the Siting Board accepted the continuing validity of its analysis of alternatives so long as Altresco complied with the conditions of the approval regarding need for the project by December 15, 1997. The Siting Board was fully aware that, if Altresco did not receive final approval until late 1997, the facility would not be constructed and operational until 2000. Thus, a delay in the project's on-line date until 2000 is a contingency for which provision was made and accepted in the Altresco Decision, and does not affect the continuing validity of the analysis of alternatives or BACT conducted in that decision.

Accordingly, the Siting Board finds that, as no party has identified information that would lead the Siting Board to conclude that its analyses of (1) alternative technologies; (2) environmental impacts, including the use of BACT; and (3) the site selection process, are now invalid, the Siting Board has no reason to revisit these analyses. Therefore, the Siting Board finds that its analyses in the Altresco Decision which demonstrate that: (1) the proposed facility 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; (2) the environmental impacts of the proposed facility would be minimized consistent with minimizing cost; and (3) Altresco has considered a reasonable range of practical facility siting alternatives, remain valid if the on-line date of the proposed facility is changed from the year 1996 to the year 2000.

3. Findings and Conclusions

In addition to the subsidiary findings on need made in the Altresco Decision and listed in Appendix A, the Siting Board has found that:

- New England will need at least 170 MW of additional energy resources in New England 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. Id. at 161 (pp. 30-31);
- Massachusetts needs at least 170 MW of additional energy resources from the proposed project for reliability purposes in the year 1997 and beyond. Altresco Decision, 2 DOMSB at 161 (p. 31);
- (1) Massachusetts' need for 170 MW of additional capacity will occur earlier than New England's need for the same, and (2) for all years in which there will be a regional need for Altresco's proposed project, i.e., for the years 2000 and beyond, the

proposed project would provide a necessary energy supply for the Commonwealth. Id. at 103, 161 (p. 31); and

- the existing record clearly establishes a need for reliability purposes in the Commonwealth in the year 2000 and beyond for an amount of capacity equal at least to that of Altresco's proposed facility (p. 32).

Consequently, the Siting Board finds that Altresco's proposed facility will provide a necessary energy supply for the Commonwealth beginning in the year 2000 and continuing thereafter.

The Siting Board has also found that:

- Altresco's proposed facility would be capable of commencing operation no earlier than February, 1998, and probably not until the summer of 1998 or later (p. 32).

Consequently, the proposed facility has the potential to commence operations at a date earlier than the first identified year of need. The Siting Board has determined that it is appropriate to consider need explicitly within a time frame beyond the first year of planned facility operation. Altresco Decision, 2 DOMSB at 58. In the Altresco Decision, the Siting Board explained that, if need has been established for the first year of operation, reviewing need over a longer time frame helps ensure that the need will continue for a number of years. Id. at 59. Further, 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. Id. For these reasons, the Siting Council previously approved two facilities which had the potential to commence operations prior to the time of Commonwealth need. See, Enron Power Enterprise Corporation, 23 DOMSC 1, at 14, 49 (1991) [approval of facility with target on-line date of 1993 based on finding of need in 1994 or 1995]; West Lynn Cogeneration, 22 DOMSC 1 at 14, 36 (1991) [approval of facility with target on-line date of 1993 based on finding of need in 1993 or 1994].

This prior practice reflects a recognition that it may be appropriate for a facility which will provide a necessary energy supply for the Commonwealth for most of its operational life to begin operations before the first identified year of Commonwealth need, especially where, as here, the determination of need has focussed primarily on providing additional capacity for reliability purposes. The early construction and operation of a facility may minimize its cost, thus ensuring that it provides a necessary supply of energy for the Commonwealth at the lowest possible cost. Alternately, the early construction and operation of a facility may make possible the displacement or retirement of older, dirtier facilities, thus ensuring that it provides a necessary supply of energy for the Commonwealth with a minimum impact on the environment. Such a facility may be the cleanest, least expensive alternative for a specific utility or municipality whose need for capacity occurs earlier than the Commonwealth's need.

Further, the Court has addressed the need for comparable treatment of non-utility and utility proposals in its remand of the EEC Decision in City of New Bedford, 413 Mass at 488. The Siting Board has noted above that our statute allows for the approval of a utility proposal to construct a facility as early as ten years before the need exists if such a proposal is consistent with the utility's most recently approved long-range forecast (See Section I.C.3 above). Therefore, the Siting Board can find no inherent reason to deny Altresco approval to construct its facility merely because its earliest date of operation might occur before, but within a reasonable time frame of the year of the administratively-determined Commonwealth need.

The probable on-line date of the Altresco facility precedes the administratively-determined date of Commonwealth need by eighteen months or less. Thus, the record establishes that the facility will provide a necessary supply of energy for the Commonwealth for all but a small portion of its operating life. Consequently, the Siting Board finds that the Altresco facility will provide a necessary supply of energy for the Commonwealth.

In Section II.B.2, above, the Siting Board has also found that:

- as no party has identified information that would lead the Siting Board to conclude that its analyses of (1) alternative technologies; (2) environmental impacts, including the use of BACT; and (3) the site selection process are now invalid, the Siting Board has no reason to revisit these analyses (p. 34); and
- its analyses in the Altresco Decision which demonstrate that: (1) the proposed facility 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; (2) the environmental impacts of the proposed facility would be minimized consistent with minimizing cost; and (3) Altresco has considered a reasonable range of practical facility siting alternatives, remain valid if the on-line date of the proposed facility is changed from the year 1996 to the year 2000 (p. 34).

Consequently, the Siting Board here reaffirms its findings that: (1) the proposed facility 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; (2) the environmental impacts of the proposed facility would be minimized consistent with minimizing cost; and (3) Altresco has considered a reasonable range of practical facility siting alternatives.

C. Viability

1. Introduction

As set forth in Section II.A.1, above, the Court's decision in Point of Pines v. Siting Board relative to the use of signed and approved PPAs leads the Siting Board to reexamine its condition relative to the viability of the proposed project. In the following section we review our findings on the issue of the viability of Altresco's proposed project.

2. Viability of the Proposed Facility

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. Cabot Power Decision, 2 DOMSB at 358; Enron Power Enterprise Corporation, 23 DOMSC 1, 89 (1991) ("Enron Decision"); Northeast Energy Associates, 16 DOMSC 335, 380 (1987). 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. Cabot Power Decision, 2 DOMSB at 358; Enron Decision, 23 DOMSC at 89, Altresco-Pittsfield, Inc., 17 DOMSC 351, 378 (1988).

In the Altresco Decision, in order to evaluate the viability of the proposed facility, the Siting Board reviewed Altresco's strategies for financing and construction of the proposed project. Altresco Decision, 2 DOMSB at 137-144. The Siting Board then reviewed the ability of the Company or other responsible entities to operate and maintain the proposed facility in a manner which would ensure a reliable energy supply. Id., 2 DOMSB at 145-146. Finally, the Siting Board considered whether the applicant's fuel acquisition strategy would reasonably ensure low-cost, reliable energy resources over the terms of the power sales agreements for the proposed project. Id., 2 DOMSB at 146-152.

With respect to the first test of viability, the extensive analysis conducted by the Siting Board showed that (1) Altresco had presented a number of scenarios addressing the sensitivity of project finances to capital costs and the amount of capacity sold under long-term contract, and that (2) the range of the assumptions submitted by Altresco, including the base case assumptions, was reasonable and consistent with scenarios reviewed by the Siting Council in prior decisions. Id., 2 DOMSB at 141. The results of the Siting Board's analysis indicated that, in accordance with acceptable internal rates of return, the proposed project would be financiable under a broad array of scenarios, but that financiability of the proposed project could not be ensured in one low case scenario for capacity sold under long-term contract. Id., 2 DOMSB at 141. The Company argued, however, that the low case scenario for capacity was inapplicable because the proposed Altresco facility was the sole project in BECo's RFP 3 Award Group for 132 MW. Id., 2 DOMSB at 140.

In considering the Company's argument, the Siting Board noted that without the BECo contract, Altresco would need to market a significant portion of its remaining capacity to be financiable. Id., 2 DOMSB at 141. The Siting Board further noted that it was unable to find need for the proposed project prior to the year 2000. Id. Finally, the Siting Board concluded that in light of the uncertainty of need in the early years of planned facility operation, the Company might have difficulty marketing a sufficient portion of its capacity, thereby raising a concern as to the facility's financiability. Id., 2 DOMSB at 141-142. However, the Siting Board noted that the PPAs that were required to demonstrate need, would also be sufficient to demonstrate financiability. Id., 2 DOMSB at 142.

In reexamining this condition, the Siting Board notes that it has found in Section II.B.2, above, that the existing record clearly establishes a need for 170 MW of additional energy resources for reliability purposes in the Commonwealth in the year 2000 and beyond for an amount of capacity equal at least to that of Altresco's proposed facility. In addition, in Section II.B.2, the Siting Board found that Altresco's proposed facility would be capable of commencing operation no earlier than February, 1998, and probably not until the summer of 1998 or later. Thus, the four year gap between the year of capacity need and the plant's projected on-line date, which was the original cause of the Siting Board's concern regarding the financiability of the proposed facility, has narrowed considerably. This change considerably diminishes the Siting Board's concern about the financiability of the proposed project.

Accordingly, based on the extensive analysis conducted by the Siting Board in the Altresco Decision, the Siting Board concludes that it is likely that the Company will be able to market a sufficient portion of the capacity of its proposed project to ensure its financiability. Consequently, the Siting Board finds that the proposed project is financiable.

In the Altresco Decision, the Siting Board found that the proposed project was likely to be constructed within applicable time frames and be capable of meeting performance objectives upon compliance with the condition that the Company provide the Siting Board with a signed copy of the agreement between Altresco and the Lynn Water and Sewer Commission ("LWSC") for provision of treated effluent and potable water. Id., 2 DOMSB at 144. As the Siting Board has found that the proposed project (1) is 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, the Siting Board finds that, upon compliance with this condition, Altresco will have established that its proposed project meets the Siting Board's first test of viability.

Further, in the Altresco Decision, the Siting Board found that Altresco had established that its proposed project meets the Siting Board's second test of viability. Id., 2 DOMSB at 152. As the Siting Board has reaffirmed this finding in Section II.A.2, above, no party has challenged this determination on appeal, and no party has identified any evidence that it would provide, were the record to be reopened, that would counter said finding, the Siting Board does not revisit it here.

3. Conclusions on Project Viability

The Siting Board has found that (1) upon compliance with the condition relative to the Company's submission of a signed copy of the agreement between Altresco and the LWSC for the provision of treated effluent and potable water, Altresco will have established that its proposed project meets the Siting Board's first test of viability in that it is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) Altresco has established that its proposed project meets the Siting Board's second test of viability in that it is likely to operate and be a reliable, leastcost source of energy over the life of its power sales agreements.

Accordingly, the Siting Board finds that, upon compliance with the above condition, Altresco will have established that its proposed project is likely to be a viable source of energy.

D. Conclusions on the Proposed Project

Based on the record evidence developed by all parties to these proceedings, the Siting Board has found that the Altresco facility, above, will provide a necessary energy supply for the Commonwealth. In addition, the Siting Board reaffirmed its findings that: (1) the proposed facility 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; (2) the environmental impacts of the proposed facility would be minimized consistent with minimizing cost; and (3) Altresco has considered a reasonable range of practical facility siting alternatives. Further, the Siting Board has found that, upon compliance with the condition in Section II.C.2, above, Altresco will have established that its proposed project is likely to be a viable source of energy.

Accordingly, based on the existing record as analyzed and set forth in the Altresco Decision as amended by this decision and the condition contained herein in response to the directive of the Court in Point of Pines v. Siting Board, the Siting Board finds that the proposed Altresco facility will provide a necessary energy supply for the Commonwealth with, on balance, a minimum impact on the environment at the lowest possible cost.

III. DECISION

In Point of Pines v. Siting Board, the Court vacated the Siting Board's decision conditionally approving the siting of Altresco's proposed facility due to the failure of the Siting Board to make an independent finding of need for that facility. 419 Mass. at 285-287. The Court left to the discretion of the Siting Board the determination as to whether to reopen hearings. Id.

Based on a review of pertinent Court decisions, the Siting Board determined that such discretion requires a review of circumstances surrounding the proceeding and the historical context of its statute in order to identify appropriate procedures to follow to address the Court's directive that the Siting Board make an independent finding of need. The Siting Board determined that all parties had been provided a full opportunity to develop a record as to the issue of need over the course of more than two years. Further, the Siting Board determined that an extensive record on need had been developed, including a complete analysis of regional and Commonwealth need. The Siting Board, nevertheless, provided all parties an opportunity to address the issues as to whether that record was sufficient and remained valid for purposes of addressing the Court's concern.

After reviewing the submissions of the parties, the Siting Board determined that the existing record is sufficient and remains valid for purposes of making an independent finding of need. The Siting Board, therefore, found no reason to exercise its discretion to reopen hearings in this proceeding.

Accordingly, the Siting Board conditionally approves the petition of Altresco to construct a 170 megawatt bulk generating facility and ancillary facilities in Lynn, Massachusetts, subject to the following condition:

1. Altresco shall provide the Siting Board with a signed copy of an agreement between Altresco and the LWSC for provision of treated effluent and potable water.

The Siting Board requires Altresco to comply with this condition within four years of the Altresco Decision, i.e., by December 15, 1997. Altresco will not receive a final approval of its proposed facility until such time as this condition has been met. Further, the Company is to comply with all other conditions and requirements set forth in the Altresco Decision as amended by Section II.A.1, above.

Robert W. Ritchie

Robert W. Ritchie
Hearing Officer

Dated this 17th day of August, 1995

APPENDIX A

Findings on Need

The following subsidiary findings on need were made by the Siting Board in the Altresco Decision, 2 DOMSB 1.

The Siting Board 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 (p. 28);
- that the reference forecast is an appropriate base case forecast for use in the analysis of regional demand for the years 1996 through 2007 (p. 43);
- 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 (p. 44)
- 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 (p. 45);
- that the linear regression forecast and the constant annual growth rate ("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 (p. 46);
- 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 (p. 47);
- that it is appropriate to adjust the 1992 CELT DSM levels in the base case (p. 50);

- 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 (p. 50);
- that the Company's high DSM case, which is the 1992 NEPOOL base DSM case, represents a reasonable high DSM case (p. 50);
- that the base supply case, as adjusted by an additional 83 MW, represents a reasonable base supply forecast (p. 54);
- 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, represents a reasonable high supply forecast for the purposes of this review (p. 56);
- that the low supply case, as adjusted by an additional 83 MW, represents a reasonable low supply forecast for the purposes of this review (p. 56);
- 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 (p. 57);
- that it is appropriate to explicitly consider need for the proposed facility within the 1996 to 2000 time period (p. 59);
- need for 170 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond (p. 61);
- 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 (p. 68);
- 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 (p. 68);
- 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 (p. 78);

- 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 (p. 79);
- 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 (p. 80);
- that the Massachusetts end-year CAGR forecast provides an acceptable forecast for use in an analysis of Massachusetts demand (p. 81);
- 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 (p. 83);
- 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 (p. 86);
- 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 (p. 87);
- 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 (p. 87);

- 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 (p. 88);
- a need for 170 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1997 (p. 92);
- 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 (p. 92);
- the Company has failed to establish need for the proposed project based on transmission system reliability grounds (p. 97);
- 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 (p. 102);
- 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 (p. 102);
- that Altresco has not demonstrated a significant improvement in air quality in Lynn due to the displacement of GE steam production (p. 102); and
- that Altresco has failed to establish that the proposed project is needed on environmental grounds (p. 102).

APPROVED by the Energy Facilities Siting Board at its meeting of August 16, 1995, by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, EFSB/DPU); Janet Gail Besser (Commissioner, DPU); David O'Connor (for Gloria Larson, Secretary of Economic Affairs); Sonia Hamel (for Trudy Coxe, Secretary of Environmental Affairs); 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 17th day of August, 1995

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 New England Power Company for Approval of its Occasional Supplement and Conversion of Two Existing 69 kV Transmission Lines to 115 kV Transmission Lines in Uxbridge, Massachusetts	)	EFSB 94-1

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
October 17, 1995

On the Decision:
Phyllis Brawarsky
William S. Febiger

APPEARANCES: Kathryn Reid, Esq.
Ellen T. Giannuzzi, Esq.
New England Power Service Company
25 Research Drive
Westborough, Massachusetts 01580-0099
FOR: New England Power Company
Petitioner

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FIGURES:

TABLES:

The Energy Facilities Siting Board hereby APPROVES the petition of New England Power Company to convert the existing 69 kV supply to the Uxbridge #321 substation to 115 kV by looping an existing 115 kV line into the Uxbridge substation, utilizing the Company's proposed route.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

New England Power Company ("NEPCo" or "Company") is the wholesale generation and transmission subsidiary of the New England Electric System ("NEES"), a public utility holding company (Post-Hearing Brief of Petitioner New England Power Company ("Brief") at n.1). NEPCo supplies almost all of the electricity distributed by the Massachusetts Electric Company ("MECo"), the NEES retail subsidiary serving customers in the Commonwealth (id.). New England Electric System, 18 DOMSC 229, 230 (1989).

NEPCo has proposed to convert the existing 69 kilovolt ("kV") supply to the Uxbridge #321 substation ("Uxbridge substation") in Uxbridge to 115 kV by looping an existing 115 kV line, located within NEPCo's Millbury-Woonsocket Right-of-Way ("ROW"), into the Uxbridge substation (Exhs. NEP-7, at 1-1; NEP-10 at 3).[1] For its primary route, NEPCo has proposed to convert two existing, 1.3 mile long, double circuited overhead 69 kV transmission lines, which extend from the Millbury-Woonsocket ROW to the Uxbridge substation, to 115 kV (Exh. NEP-7, at 1-1, 2-4). NEPCo has identified two alternative routes from the Millbury-Woonsocket ROW to the Uxbridge substation including (1) two new, 1.8 mile long, overhead, 115 kV transmission lines that would follow a railroad ROW and a new private ROW, and (2) two new, 1.7 mile long, underground 115 kV transmission lines that would follow public streets and an existing private ROW (id. at 1-1).

In addition to the proposed 115 kV transmission lines, NEPCo has proposed to install two new 115/13.8 kV transformers, circuit breakers and associated equipment at the Uxbridge substation (id. at 1-2).

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1 The Company indicated that looping the existing 115 kV line refers to the extension of the 115 kV line from its mainline location to the substation and then back out to the mainline such that the 115 kV line runs through the substation (Exh. NEP-10, at 3). See Figure 2.

Pursuant to G.L. c. 164, § 69J, no electric company shall commence construction of a jurisdictional energy facility (See Section I.C, below) unless a petition for approval of construction has been approved by the Massachusetts Energy Facilities Siting Board ("Siting Board"). In addition, in the case of an electric company which is required by G.L. c. 164, § 69I to file a long-range forecast with the Department of Public Utilities ("Department"), the facility must be consistent with the electric company's most recently approved long-range forecast. G.L. c. 164, § 69J. NEES' Massachusetts retail subsidiary, i.e., MECo, is required to make such a filing. After reviewing MECo's most recent long-range forecast filing, the Department approved MECo's forecast. Massachusetts Electric Company, D.P.U. 94-112 (1994).

B. Procedural History

On December 15, 1994, NEPCo filed with the Siting Board its petition to convert two existing 1.3 mile, 69 kV, double-circuited, overhead transmission lines to 115 kV and to upgrade related facilities as described herein. On April 3, 1995, the Siting Board conducted a public hearing on the petition in the Town of Uxbridge. In accordance with the direction of the Hearing Officer, NEPCo provided notice of the public hearing and adjudication. No petitions to intervene or to participate as an interested person were submitted.

The Siting Board conducted evidentiary hearings on July 11 and 12, 1995. NEPCo presented three witnesses: Francis R. Barys, an engineer in the Protection and Planning Department of the New England Power Service Company ("NEPSCo"), who testified regarding the need for the proposed facility and alternatives thereto; Mark S. Browne, a senior engineer in the Transmission Line Engineering Department of NEPSCo, who testified regarding cost and environmental impacts of the proposed facility; and Dr. Deborah E. Weil, an independent scientist employed by Bailey Research Associates, who testified regarding electric and magnetic fields.

The Hearing Officer entered 110 exhibits into the record, consisting primarily of NEPCo's responses to information and record requests. NEPCo entered 12 exhibits into the record.

NEPCo filed its Brief on August 9, 1995. The Siting Board issued supplemental information requests to clarify the Company's responses to record requests on that same day. The Company completed its responses to the supplemental information requests on August 16, 1995.

C. Jurisdiction

The Company's petition is filed in accordance with G.L. c. 164, § 69H, which requires the Siting Board "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 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 construction permit may be issued by another state agency.

The Company's proposal to construct a 1.3 mile, 115 kV electric transmission line falls squarely within the second definition of "facility" set forth in G.L. c. 164, § 69G. That section states, in part, that a facility is:

> (2) any new electric transmission line having a design rating of sixty-nine kilovolts or more and which is one mile or more in length except reconductoring or rebuilding of existing transmission lines at the same voltage.

The Company also proposes to install two new 115/13.8 kV transformers at the Uxbridge substation. The third definition of facility set forth in G.L. c. 164 § 69G is pertinent in determining whether the transformers are jurisdictional facilities. In that third definition a facility is defined as:

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

In Commonwealth Electric Company, 17 DOMSC 249, 263 (1988) ("1988 ComElectric Decision"), the Energy Facilities Siting Council ("Siting Council")[2] established

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2 The Siting Council was the predecessor agency of the Siting Board. Chapter 141 of the Acts of 1992 ("Reorganization Act"). The Reorganization Act maintains decisions of the Siting Council as precedent for the Siting Board. Reorganization Act, § 46.

a two-part standard for determining whether a structure is a facility under the third definition of facility set forth in G.L. c. 164, § 69G. In that case the Siting Council determined that a structure is a facility if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility. Id.

With regard to the first part of the definition, the transformers are clearly subordinate to the proposed transmission line.[3]

With regard to the second part of the definition, the Company asserted that the transformers would provide benefit independent of the proposed facilities (Exh. HO-N-7; Tr. 1, at 67-68; Brief at n.3). The Company stated that, even without installation of the proposed transmission line, replacement of the two transformers at the Uxbridge substation with increased transformer capacity is necessary to provide firm capacity for the Uxbridge substation load (Exh. HO-N-7). The Company explained that each of the existing transformers will exceed its summer emergency capability with the outage of either transmission line or the other transformer at the Uxbridge substation (id.; Exh. HO-N-15). See Section II.A.3, below.

The Siting Board accepts the Company's argument that increased transformer capacity is necessary to provide firm capacity for the Uxbridge substation load. The need for increased transformer capacity, however, does not create a situation in which every option to meet that need would necessarily provide a benefit outside of the relationship of that option to the jurisdictional facility. The Siting Board notes that the proposed transformers, which would step voltage down from 115 kV to 13.8, could not be used at the Uxbridge substation without the installation of a 115 kV transmission line to the substation. Therefore, the proposed 115/13.8 kV transformers would not be capable of providing a benefit outside of their relationship to the proposed transmission line.

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3 The Company stated that the transformers may be considered supplementary to the proposed transmission line due the relationship of the transmission line to the transformers -- transformers step down the voltage of the power delivered via the transmission line so that the power can be delivered at a distribution voltage level (Exh. HO-N-17). The Company defined supplementary as "something that makes an addition" (Exh. HO-N-17).

Accordingly, pursuant to the definition of facility set forth in the 1988 ComElectric Decision, the Siting Board finds that the proposed 115/13.8 kV transformers are facilities within the meaning of the third definition of facility in G.L. c. 164, § 69G.

D. Scope of Review

In accordance with G.L. c. 164, § 69H, before approving an application to construct facilities, the Siting Board requires applicants to justify facility proposals in three phases. First, the Siting Board requires the applicant to show that additional energy resources are needed (see Section II.A, below). Next, the Siting Board requires the applicant to establish that its project is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Board requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, and that the proposed site for the facility is superior to a noticed alternative site[4] in terms of cost, environmental impact, and reliability of supply (see Section III, below).

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4 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 for purposes of the proceeding.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

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. In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources[5] to meet reliability, economic efficiency, or environmental objectives. The Siting Board must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

2. Description of the Existing System

The Company indicated that the Uxbridge Power Supply Area ("PSA") is supplied by three bulk transmission substations -- the Uxbridge substation,[6] the Whitins Pond substation in Northbridge and the Depot Street substation in Milford (Exh. HO-N-19; Brief at 7). The Uxbridge substation is supplied at 69 kV from the Millbury #1 substation ("Millbury substation") in Millbury via two 69 kV transmission lines, the K-11 and L-12 lines, which extend along NEPCo's existing Millbury-Woonsocket ROW (Exhs. NEP-10, at 2; NEP-7 at 2-4). Two 69 kV tap lines, the K-11T and L-12T lines, connect the K-11 and L-12 lines to the Uxbridge substation along a 1.3 mile ROW known as the Uxbridge spur (Exh. NEP-7, at 2-1, 2-2, 3-3). See Figure 1. The K-11/K-11T and L-12/L-12T lines are supported on a single line of double circuit steel towers for the entire distance of 12.4 miles from the

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5 In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions, including, but not limited to, electric generating facilities, electric transmission lines, energy or capacity associated with power sales agreements, and energy or capacity associated with conservation and load management ("C&LM").

6 The Uxbridge substation serves load in Uxbridge, Millville, and parts of Blackstone, Douglas, Northbridge and Sutton, Massachusetts (Exh. NEP-10, at 2).

Millbury substation to the Uxbridge substation (Exh. NEP-10, at 3). Two 69/13.8 kV transformers at the Uxbridge substation step the power down from 69 kV to 13.8 kV (Exh. NEP-7, at 2-1). The Company indicated that there are also two 13.8 kV distribution lines on single poles that extend along the Uxbridge spur ROW (id. at 3-16; Tr. 1, at 97).

The Company stated that prior to 1990, the Uxbridge substation was supplied by both the Millbury substation and Narragansett Electric Company's Woonsocket, Rhode Island substation ("Woonsocket substation") via the K-11/K-11T and L-12/L-12T lines, with half the load being served by each substation (Exh. NEP-7, at 2-1, 2-2; Tr. 1, at 35). The Company explained that in 1990, the 115/69 kV transformer at the Woonsocket substation failed and the supply to the Uxbridge substation was changed to its present configuration (Exhs. NEP-7, at 2-1; HO-N-10b).[7] The Company asserted that in 1990 the present configuration was the only course available to maintain two 69 kV supplies to the Uxbridge substation and that there were no alternative sources that could have been immediately utilized to supply the Uxbridge substation (Exh. NO-N-26).

The Company stated that the Millbury-Woonsocket ROW also is occupied by two 115 kV transmission lines, the Q-143 and R-144 lines, which connect Millbury and Woonsocket substations and extend south to a substation in Providence, Rhode Island (Exhs. NEP-7, at 2-4; HO-RR-3b; Brief at 7). The Company noted that the Whitins Pond substation is served by the Q-143 line (Exh. HO-N-11b).[8,9] The Company indicated that, in addition to supplying area loads, the Q-143 and R-144 lines provide a valuable bulk power transfer path

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7 The Company indicated that although the K-11 and L-12 lines extend between the Woonsocket and Millbury substations, the K-11 line is open and there is an open switch on the L-12 line between the tap point and the Woonsocket substation (Exh. NEP-7, at 2-2).

8 The Company noted that the Whitins Pond substation is located between the Millbury and Uxbridge substations; there are no transmission or subtransmission lines connecting the Whitins Pond and Uxbridge substations (Exh. HO-N-11b). Distribution feed ties which link the two substations are normally open (id.).

9 The Q-143/R-144 lines also supply two substations in Providence, Rhode Island (Exh. HO-RR-3b, attach.; Brief at 7).

to the central Massachusetts areas from the southeast Massachusetts/Rhode Island region (Exhs. HO-A-16; HO-A-19).

The Company also noted that the Depot Street substation is located seven miles to the northeast of the Uxbridge substation and is served by two 115 kV transmission lines that extend between the Millbury substation and the Medway substation in Medway (Exhs. NEP-7, at 2-1, 2-4; HO-N-14a). Two 13.8 kV subtransmission lines, designated as the 7U and 8U lines, connect the Uxbridge substation and the Depot Street substation (Exhs. NEP-7 at 2-4; NEP-10, at 2).[10] See Figure 1.

3. Reliability of Supply

The Company asserted that the proposed project is needed in order to provide a reliable supply of electricity to the area served by the Uxbridge substation (Exh. NEP-7, at 2-1). The Company identified two problems with the present supply to the Uxbridge substation such that the existing supply configuration does not meet the reliability criteria of the Company (id.; Exh. NEP-10, at 2-3). The Company stated that the current demand from the Uxbridge area exceeds the firm capability of equipment under contingency conditions (id.). The Company further stated that the location of the two transmission lines serving the Uxbridge substation on a single line of double-circuit towers makes both lines susceptible to a simultaneous fault which would result in an outage for the customers served by the Uxbridge substation (id.).

In this Section, the Siting Board first examines the reasonableness of the Company's system reliability criteria. The Siting Board then evaluates: (1) whether the Company uses reviewable and appropriate methods for assessing system reliability based on load flow analyses; (2) whether existing and projected loads, under certain contingencies, exceed the Company's reliability criteria, thereby requiring additional energy resources; and (3) whether acceleration of C&LM programs could eliminate the need for such additional energy resources.

10 The 7U line supplies a distribution substation in Milford and the 8U line supplies the Mendon #332 substation, which is a distribution substation in Mendon (Exh. NEP-10, at 2).

a. Reliability Criteria

In regard to reliability objectives, the Company described three classes of service reliability and system design criteria applicable to the classes of transmission and distribution found in the proposed project area (Exh. NEP-7, app. B-2). First, with regard to reliability of service to customer load, the Company indicated that the indices of the level of service reliability are frequency and duration of customer outages (id., sec. 2.5). The Company stated that its system design criteria for firm supply require that, in the event of the outage of any one major facility, the remaining system must be capable of serving the customer load within a time period no longer than that required for automatic switching (id.). The Company's system design criteria require that "nonfirm peak load in a contiguous area ... not exceed 30 MW" and that "a 3-hour outage once in three years, or a 24-hour outage once in ten years ... not [be] exceeded for load above 20 MW" (id., sec. 2.5.1).

The system design criteria also require that "the development of supply facilities should preclude equipment loadings above emergency capabilities, and voltage regulations beyond acceptable limits" (id., app. B-2; Exh. NEP-10, at 2-3). Specifically, emergency equipment capabilities must not be exceeded for the loss of a transformer or the loss of an overhead line (Exh. NEP-7, app. B-2, sec. 2.3).[11]

Second, the Company indicated that the system design criteria provide that:

> simultaneous outages of both circuits on overhead double circuit structure may result in the loss of an entire area load, but ... it is reasonable to assume that both circuits will not be permanently faulted, and that at least one circuit can be restored to service quickly by a successful reclosure (Exh. HO-N-13a).

In order to conform to the above assumption, the Company stated that the system should be designed so that both circuits will not be permanently faulted (Brief at 10, citing, Exh. HO-N-13a).

Third, the Company indicated that maintaining the availability of bulk power transfer capability, such as that provided by the Q-143 and R-144 lines, also is a reliability factor

11 The Company indicated that acceptable limits on voltage fluctuation are ten percent for normal and 15 percent for emergency conditions (Exh. NEP-7, App. B-2, sec. 2.4).

when designing facilities that may affect such availability (Exhs. HO-A-16; HO-A-19).[12] The Company did not provide reliability criteria, based on the level of bulk power transfer operations or other indicators, that justify particular reliability levels for bulk power corridors.

The Company indicated that its present service reliability criteria were established in 1975, in order to minimize overall cost of supply while maintaining service reliability (Exh. HO-N-13c).[13] The Company indicated that the current reliability standards of four other utilities provide for a threshold for firm supply in the range of its 30 MW level (Exh. HO-N-28).[14]

The Siting Council consistently found that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain system reliability. New England Power Company, 21 DOMSC 325, 339 (1991) ("1991 NEPCo Decision"); Middleborough Gas & Electric Department, 17 DOMSC 197, 206-219 (1988); Holyoke Gas and Electric Department, 3 DOMSC 1, 7 (1978).

With respect to the specific load levels reflected in the Company's reliability criteria for area loads, the Company has provided a summary of the reasons for its establishing the firm supply threshold of 30 MW and, in addition, has provided comparable reliability

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12 The Company explained that facilities that supply area loads, such as tap or loop extensions, can increase the exposure of bulk power transfer lines to outage contingencies (Exh. HO-A-19).

13 The Company stated that a study completed in 1975 concluded that increasing the normal maximum loading on 15 kV feeders and increasing the firm supply threshold to distribution substations from 5 MW to 30 MW would reduce overall costs by over 40 percent (Exh. HO-N-13c). The Company added that the study also determined that existing levels of customer service could be maintained by installing automatic sectionalizing devices on each 15 kV distribution feeder (id.).

14 The Company noted that the threshold for firm supply is: (1) 25 to 30 MW for Boston Edison; (2) 30 MW for Northeast Utilities and Public Service of New Hampshire; and (3) 40 to 45 MW for Pennsylvania Power and Light (Exh. HO-N-28).

standards of other utilities serving the Northeast. Although the record in this case does not address the factors that support its use of a firm supply threshold of 20 MW where longer outages have been experienced, the Siting Council has previously held, in a review of a transmission line proposed by the Company, that "the approach of establishing a threshold for firm supply based on the size of contiguous load, with a lower threshold where outage experience gives rise to customer dissatisfaction, is reasonable."[15] 1991 NEPCo Decision, 21 DOMSC at 339. Consequently, the Siting Board finds that the Company's criteria regarding firm service to area loads are reasonable.

With respect to the Company's criterion regarding simultaneous loss of overhead double-circuit lines, the Siting Board notes that concern about such a loss is warranted if the need for a two-line supply is clear, e.g., if the lines provide a needed firm capability or if the combined capacity of the lines is needed to meet peak load under normal operations. The criterion may be inappropriate, however, if the need for a two-line supply is clearly unsupported based on the Company's other reliability criteria. Thus, the Siting Board finds that the Company's criterion regarding simultaneous loss of overhead double-circuit lines is reasonable, provided that said criterion is considered in conjunction with other reliability criteria of the Company that relate to the need for two lines.

With respect to the Company's identification of bulk power transfer capability as an additional reliability factor in the design of system modifications that may affect such capability, the Siting Board agrees that bulk power transfers can be essential for avoiding significant customer outages, unacceptable voltage levels or thermal overloads. Absent more specific criteria, however, it is unclear whether and how the Company considers indicators of the importance of such transfers -- for example the purpose of the transfers or thresholds as to the size or frequency of transfers -- in applying particular reliability standards. Further, it is unclear whether the reliability standard to be applied for bulk power transfers which exceed the threshold or other indicator of importance is the same as, or more or less stringent than, the reliability standard to be applied for serving area loads that exceed

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15 In that review, the Siting Council found that the Company's reliability criteria, including both the 30 MW and the 20 MW criteria, were reasonable. 1991 NEPCo Decision at 339.

particular thresholds. In future reviews where the reliability of bulk power transfer capability is a factor, applicants will be required to identify quantitative or other specific criteria that allow the importance of such capabilities to be established on a case-specific basis.

Accordingly, based on the foregoing, the Siting Board finds that the Company's reliability criteria are reasonable for purposes of this review.

b. Load Forecasts

i. Description

For the Uxbridge PSA, the Company provided information regarding historical system-coincident peak demand for 1980 through 1994[16] and forecasted base-case and high-case system-coincident peak demand for the years 1995 through 2013 (Exh. HO-N-1b). The Company stated that its PSA forecasts are statistical forecasts of seasonal system-coincident peak demand that are used for purposes of system transmission and area supply planning (Exh. HO-N-1a).

The Company indicated that the PSA forecasts are developed by allocating to the PSA its proportional share of the long-term load forecast of MECo peak demand, developed in the Companies' Integrated Resource Plan ("IRP") (id.). Specifically, the Company projects allocated PSA load by (1) regressing historical coincident PSA peaks for both summer and winter against the historical peak for MECo, and (2) applying coefficients from the regressions to the IRP forecast of MECo seasonal peak (id.). The Company added that the PSA forecast is then (1) calibrated so that the growth of the sum of the PSAs matches the MECo IRP forecast, and (2) adjusted to reflect the gain or loss of large customers or other events which are not reflective of the historical pattern of the PSA load (id.). The Company noted that, in order to reflect uncertainties inherent in system-coincident and peak-day weather, a high-case forecast of seasonal peaks is also developed for each PSA by adding two standard errors of the regression to each year's base case PSA forecast (id.).

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16 NEPCo indicated that the seasonal coincident historic peaks attributed to a PSA are calculated as the total of meter readings at substations within the PSA (Exh. HO-N-1a).

The Company also provided Uxbridge substation loads coincident with the system peak for the years 1988 through 1994 (Exh. HO-N-3).[17] The Company indicated that the Uxbridge substation load, coincident with system peak, was 23.5 MW in 1993 and 19.4 MW in 1994 (id.).[18] The Company explained that the PSA is the smallest unit for which forecasts are developed and that it does not prepare separate forecasts of load growth at specific distribution substations (Exh. HO-N-2b, 2c). However, the Company estimated that the Uxbridge substation accounts for approximately 11 percent of the combined load of the Uxbridge and Webster PSAs, based on its historical percentage of 8.4 percent to 11.3 percent over the 1988 to 1994 time period (Exhs. NEP-7, revised app. B-1; HO-N-3).[19]

ii. Analysis

In forecasting load for the Uxbridge substation, the Company first prepared the PSA forecast and then derived the Uxbridge substation forecast from the PSA forecast, based on the historical relationship of Uxbridge substation peak to the PSA peak. In presenting its PSA forecast, the Company adequately explained its derivation of historic trends in order to prorate the MECo system forecast into separate PSA forecasts. While the Company described certain PSA-specific adjustments that would be applied to the PSA forecast, the Company did not provide a systematic methodology for the adjustment of the PSA forecast either to account for PSA-specific information, or to conform to the system forecast. Thus, the Company relied on both quantitative and judgmental techniques in its forecast of PSA load growth.

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17 The Company indicated that the Uxbridge substation, coincident with system peak, load ranged from 17.0 MW to 23.5 MW during the 1988 to 1994 period (Exh. HO-N-3).

18 The Company noted that the non-coincident 1994 summer peak at the Uxbridge substation reached 29.6 MW (Exh. HO-N-15).

19 The company indicated that until 1993 the Uxbridge area was included in the Millbury PSA (Exh. HO-N-1c). In 1993, the Millbury PSA was separated into the Uxbridge PSA and the Webster PSA (id.).

In an earlier review of a transmission line proposed by the Company, the Siting Council stated that, in future facility reviews, where a company projects load growth for a portion of its service territory, the Siting Council will require such company to use quantitative techniques, where sufficient data is available, or other systematic techniques, and to document all pertinent assumptions to support the allocation of system-wide growth to service areas and to individual substations within the service areas. 1991 NEPCo Decision, 21 DOMSC at 344.

Here, the Company has relied on quantitative techniques with adjustments for forecasting load at the PSA level, and has provided a reasonable explanation for its estimation of load growth at the substation level, based on the PSA forecast. Further, as will be discussed in Section II.A.3.c.i, below, the proposed facilities are needed based on existing load levels. Accordingly, for purposes of this review, the Siting Board finds that the Company's load forecast methodology is reasonable and acceptable.

c. Contingency Analysis

In this Section, the Siting Board considers whether there is a need for additional energy resources based either on (1) the Company's reliability criteria with regard to equipment loadings, or (2) its reliability criteria with regard to double circuit outages.

i. Exceedance of Firm Capability of Equipment

The Company asserted that under 1993 summer peak load and foreseeable contingencies, existing facilities would be loaded in excess of summer emergency capabilities (Exhs. HO-N-6; HO-N-15). In support of its assertion, the Company provided a set of load flow analyses, based on 1993 and 1994 system-coincident peak loads at the Uxbridge substation, to simulate system operation under normal conditions and with each major component out of service (Exhs. HO-N-14; HO-N-15). The proposed facilities were not included in this set of load flow analyses (Exhs. HO-N-14; HO-N-15). As the basis for assessing system adequacy, the Company explained that these load flow diagrams identify system problems such as equipment loading above designated ratings for emergency conditions and voltage below designated minimum levels (Exhs. HO-N-14; HO-N-15).

The Company provided the summer emergency capabilities of equipment serving the Uxbridge substation load as follows: (1) the K-11/11T and L-12/12T transmission lines, 18 megavoltamperes ("MVA"); (2) transformer T1, 25.9 MVA; and (3) transformer T6, 18.2 MVA (Exh. HO-N-12). The Company provided load flow analyses, assuming the 1993 summer peak load of 23.5 MW and the 1994 summer peak load of 19.4 MW, for the outage of each of the existing 69 kV transmission lines and transformers with normal load operation on the distribution system (Exhs. HO-N-14b to 14e; HO-N-15b to 15e). In addition, the Company provided a second set of load flow analyses for 1993 and 1994 summer peak loads under the same contingencies, assuming an alternative operating configuration for the distribution system ("alternative distribution configuration") (Exhs. HO-N-15g to 15k; HO-N-29a to 29e). The Company explained that, under peak load conditions, it currently uses the alternative distribution configuration in order to prevent overloading on the 7U and 8U distribution lines in the event of an outage of the K-11/11T or L-12/12T lines (Exh. HO-N-15).[20]

With normal load operation of the distribution system,[21] the Company's load flow analyses demonstrate exceedances of equipment capabilities under 1993 summer peak load as follows: (1) the outage of the L-12/12T transmission or the T1 transformer would cause the K-11 line to be loaded at 18.7 MVA, the K-11T line to be loaded at 18.4 MVA and the T6 transformer to be loaded at 18.3 MVA[22]; (2) the outage of the K-11/11T transmission line

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20 The Company indicated that the alternative distribution configuration would involve switching a large industrial customer from the 7P line, which normally supplies a distribution substation and said large industrial customer, to the 8U line in order to prevent an overload of the 7P line (Exh. HO-N-15e). In addition, the Company indicated that it would open the 7U and 8U lines between the Uxbridge and Depot Street substations in order to supply the Mendon #332 substation exclusively from the Uxbridge substation (Exh. HO-N-15).

21 The Company indicated that the 7U and 8U lines are not opened between the Uxbridge substation and Depot Street substation under normal load operation of the distribution system (Exh. HO-N-15b through 15e).

22 Under this contingency, loadings would be 3.9, 2.2, and 0.5 percent above emergency capabilities for the K-11 line, K-11T line and transformer T6, respectively (Exhs. HO-N-12; HO-N-15b, 15d; Tr. 1 at 52-56).

or the T6 transformer would cause the L-12 line to be loaded at 18.7 MVA and the L-12T line to be loaded at 18.3 MVA[23] (Exh. HO-N-15b to 15e; Tr. 1, at 52-56). The Company indicated that there are no equipment overloads under 1994 summer peak load of 19.4 MW and the aforementioned operating conditions (Exh. HO-N-14c).

With the use of the alternative distribution configuration, the Company indicated that exceedances of emergency summer capabilities would be greater during peak load conditions for the Uxbridge substation and the Depot Street substation (Exh. HO-N-15). The Company provided load flow analyses assuming the 1993 summer peak load of 23.5 MW, the outage of each of the 115 kV transmission lines and transformers, and the alternative distribution configuration (Exh. HO-N-15h to 15k). These load flow analyses demonstrate that (1) the outage of the L-12/12T transmission line or the T1 transformer would cause the K-11 line to be loaded at 30.0 MVA, the K-11T line to be loaded at 29.1 MVA and the T6 transformer to be loaded at 29.0 MVA,[24] and (2) the outage of the K-11/11T transmission line or the T6 transformer would cause the L-12 line to be loaded at 29.9 MVA, the L-12T line to be loaded at 29.1 MVA and the T1 transformer to be loaded at 28.9 MVA[25] (Exh. HO-N-15h to 15k; Tr. 1, at 52-56).

The Company stated that under the alternative distribution configuration and the aforementioned contingencies, equipment loadings also exceeded emergency ratings under the 1994 peak load of 19.4 MW (Exh. HO-N-29). In support, the Company provided load flow analyses which demonstrate that: (1) the outage of the L-12/12T transmission line or the T1 transformer would cause the K-11 line to be loaded at 25.9 MVA, the K-11T line to be

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23 Under this contingency, loadings would be 3.9 and 1.7 percent above emergency capabilities for the L-11 line and L-11T line, respectively (Exhs. HO-N-12; HO-N-15c, 15e; Tr. 1 at 52-56).

24 Under this contingency, loadings would be 66.7, 61.7 and 59.3 percent above emergency capabilities for the K-11 line, K-11T line and transformer T6, respectively (Exhs. HO-N-12; HO-N-15h; HO-N-15j; Tr. 1, at 52-56).

25 Under this contingency, loadings would be 66.1, 61.6 and 11.6 percent above emergency capabilities for the L-12 line, L-12T line and transformer T1, respectively (Exhs. HO-N-12; HO-N-15i; HO-N-15k; Tr. 1, at 52-56).

loaded at 25.1 MVA and the T6 transformer to be loaded at 25.0 MVA,[26] and (2) the outage of the K-11/11T transmission line or the T6 transformer would cause the L-12 line to be loaded at 25.9 MVA and the L-12T line to be loaded at 25.1 MVA (Exh. HO-N-29; Tr. 1, at 52-56).[27] The loading on the T1 transformer would be 25.0 MVA, 96 percent of its emergency summer capability (Exh. HO-N-29).

The Company stated that the maximum safe loading level at the Uxbridge substation, assuming the alternative distribution configuration, is 12.5 MW (Exh. HO-RR-2). The Company provided load flow analyses, assuming a 12.5 MW load and the alternative distribution configuration, which demonstrated that under the contingency of losing the K-11 or L-12 transmission lines or the T1 or T6 transformers, remaining equipment would be loaded to 98 percent of its summer emergency capability (Exh. HO-RR-2b to 2e). In addition, the Company provided load flow analyses, assuming a 13.0 MW load and the aforementioned conditions, which demonstrated that under said contingencies, remaining equipment would be loaded to 101 percent of summer emergency capabilities (Exh. HO-RR-2f to 2j).

The Company stated that under contingency conditions, 5.6 MW of the Uxbridge substation load could be transferred to adjacent substations through distribution feeder ties (Exh. HO-RR-5). However, the Company stated that, even with such a transfer, equipment loadings would exceed summer emergency capabilities at the 1994 summer peak load level of 19.4 MW under certain contingencies (Exh. HO-N-25).[28]

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26 Under this contingency, loadings would be 43.9, 39.4, and 37.4 percent above emergency capabilities for the K-11 line, K-11T line and transformer T6, respectively (Exhs. HO-N-12; HO-N-29b; HO-N-29d; Tr. 1, at 52-56).

27 Under this contingency, loadings would be 43.9 and 39.4 percent above emergency capabilities for the L-12 line and L-12T line, respectively (Exhs. HO-N-12; HO-N-29c; HO-N-29e; Tr. 1, at 52-56).

28 The Company provided a load flow analysis, assuming the loss of both the K-11/11T and L-12/12T lines and an Uxbridge substation load of 19.4 MW, which demonstrated that the load on the 7U line would exceed its summer emergency capability and the 8U line would be loaded to 98 percent of its summer emergency capability (Exh. HO-N-25).

In its load flow studies, the Company consistently related its assumptions and conclusions to its reliability criteria. The Siting Board finds that the Company used reviewable and appropriate methods for assessing the reliability of supply based on load flow analysis.

Further, the Siting Board finds that the Company's load flow analyses demonstrate that under 1994 peak load conditions, each of four contingencies -- the loss of the K-11/11T transmission line, the L-12/12T transmission line, the T1 transformer, and the T6 transformer -- would cause remaining equipment to be loaded above emergency summer capabilities. The Siting Board, therefore, finds that the supply to the Uxbridge substation currently does not meet the Company's reliability criteria in the event of the loss of the K-11/11T transmission line, the L-12/12T transmission line, the T1 transformer, or the T6 transformer. Consequently, the Siting Board finds that there is a need for additional energy resources based on the Company's reliability criteria with regard to equipment loadings.

ii. Double Circuit Outage

The Company asserted that providing firm supply to the Uxbridge substation in the form of two adequate supplies is justified based on past outage experience and the Company's commitment to providing reliable electrical service to the customers supplied from that substation (Exh. HO-RR-16). The Company stated that its Guide for Area Supply Planning specifies that, to avoid the problem of simultaneous outage of both circuits on overhead double circuit structures which could lead to the loss of an entire area load, the system should be designed so that both circuits will not be permanently faulted at the same time (Brief at 10, citing, Exh. HO-N-13a). The Company further indicated that, as a result of the loss of the Woonsocket transformer in 1990, the 69 kV supply configuration to the Uxbridge substation has been diminished and the exposure of the remaining supply to a double circuit outage has become unacceptable based on the Company's reliability criteria (Exh. HO-N-8a).

The Company explained that the K-11/11T and L-12/12T transmission lines extending from the Millbury substation, which are Uxbridge substation's only supply source under the current supply configuration, are supported on a single line of double circuit steel towers for their entire length of 12.4 miles between Millbury and Uxbridge substations (Exhs. NEP-7, at 2-1; NEP-10, at 3). The Company noted that on February 16, 1990, there was a permanent double circuit outage of the K-11 and L-12 lines due to lightning that resulted in the loss of supply to the Uxbridge substation and a customer outage lasting seven hours (Exh. HO-N-8a).[29] The Company maintained that the proposed project would decrease the risk of double circuit outages by 89 percent (Exh. HO-RR-16).

Based on the Company's record of supply system outages since 1990, including a seven-hour outage in 1990, the Siting Board agrees it is reasonably likely that a double circuit outage could occur, resulting in the loss of supply to the Uxbridge substation. Further, based on the double-circuit outage criteria as set forth by the Company, the present supply system does not meet the Company's reliability criteria relative to overhead double circuit structures.

However, the Siting Board found in Section II.A.3.a, above, that the Company's criterion regarding simultaneous loss of overhead double-circuit lines should be considered in conjunction with any other reliability criteria of the Company that relate to the need for two lines. We note that, because the Uxbridge substation load has reached 20 MW,[30] the Company's criteria related to providing firm supply to contiguous load of 20 MW or more is potentially applicable.

The Company's Guide for Area Supply Planning states that changes to the supply system can be justified if a three-hour outage once in three years or a 24-hour outage once in ten years is exceeded if the load served is at least 20 MW (Exh. HO-RR-16).[31] The Siting

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[29] The Company noted that there have been eight other outages of both lines since 1990 where both lines were out of service for up to one minute (Exh. HO-N-22).

[30] The Company stated that the Uxbridge substation coincident peak load exceeded 20 MW in 1988, 1991, and 1993 and that the non-coincident substation peak exceeded 20 MW in 1994 (Exhs. HO-N-3; HO-N-19).

[31] The Company explained that the three-hour or 24-hour outage refers to the amount of time a facility is out of service due to a single event rather than the accumulation of outage time due to a number of events within the three- or ten-year time period (Exh. HO-RR-16).

Board notes that the seven-hour outage experienced in February 1990 significantly exceeded the three-hour threshold for an outage that would warrant changes to provide firm supply for a 20 MW load. At the same time, it is unclear whether the recurrence frequency for such outages is sufficient for the Company's 20 MW load firm supply criteria to apply.

Nevertheless, the outage experience under the current supply configuration for Uxbridge substation, which includes an outage of considerable duration just five years ago, appears to be at least close to a level of outage experience that would warrant changes to provide firm supply based on the Company's reliability criteria for a substation load of 20 MW or more. Thus, it is reasonable for the Company to maintain the integrity of its two-line supply by ensuring that such supply is not subject to double circuit outages, consistent with its reliability criteria.

Accordingly, based on the foregoing, the Siting Board finds that the Company has established that supply to the Uxbridge substation does not meet the Company's reliability criteria with respect to overhead double circuit structures, considered in conjunction with other applicable criteria. Consequently, the Siting Board finds that there is a need for additional energy resources based on the Company's reliability criteria with regard to double circuit outages.

d. Accelerated Conservation and Load Management

G.L. c. 164 §69J requires a petitioner to include a description of actions planned to be taken to meet future needs and requirements, including the possibility of reducing requirements through load management. The Company asserted that acceleration of both its conservation and its load management[32] programs would not address the need for additional

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[32] Load management is a measure or action designed to modify the time pattern of customer electricity requirements, for the purpose of improving the efficiency of an electric company's operating system. 220 CMR § 10.02. For example, a utility may reach an agreement with a manufacturer that uses electricity whereby that manufacturer will curtail its use during peak times when the utility's system, as a whole, is facing increasing demands for electricity for cooling or heating purposes. During non-peak times the manufacturer may then resume its use of electricity. The utility providing electricity has, therefore, managed its load, thereby decreasing its (continued...)

energy resources based on equipment loadings given the large amount of load reduction that would be required (Exh. HO-A-1; Brief at 13). The Company stated that it would not be feasible to reduce the present 23.5 MW peak load at the Uxbridge substation to 12.5 MW in order to maintain existing facilities within their emergency ratings (Brief at 13).

The Company provided a list of its current DSM programs (Exh. HO-N-4a). In addition, the Company provided projections of avoided summer MW for the MECo system due to incremental DSM above the 1993 levels for the years 1994 through 1996 as follows: (1) 1994, 12 MW; (2) 1995, 37 MW; and (3) 1996, 64 MW (Exh. HO-N-4b). The Company stated that it does not prepare forecasts of DSM savings at the PSA level but estimated the incremental DSM savings applicable to the Uxbridge/Webster PSA for the years 1994 to 1996 by multiplying the total projected MECo DSM savings by the share of Company load represented by the Uxbridge/Webster PSA (id.). The Company indicated that allocated DSM savings for the Uxbridge/Webster PSA are as follows: (1) 1994, 0.85 MW; (2) 1995, 3.45 MW; and (3) 1996, 4.49 MW (id.). The Company acknowledged that DSM savings would not necessarily be evenly apportioned to the Company load as assumed under its method of allocation (id.).[33]

As noted in Section II.A.3.b.i, above, the Uxbridge substation load is approximately 11 percent of the Uxbridge/Webster PSA load. The Siting Board notes that even if the entire Uxbridge/Webster PSA 1996 DSM savings were applied to the 1994 summer coincident Uxbridge substation peak load, which was less than the 1993 summer peak, facilities would still be loaded above emergency capabilities in the event of the outage of major substation

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[32](...continued)
need for additional peak capacity.

Conservation, on the other hand, is a technology, measure, or action designed to decrease the kilowatt or kilowatthour requirements of an electric end-use, thereby reducing the overall need for electricity. Id. Both conservation and load management are demand side management ("DSM") measures.

[33] The Company indicated that the MECo system load is 37 percent residential and 63 percent commercial/industrial while the Uxbridge area load is 61 percent residential and 39 percent commercial/industrial (Exh. HO-N-5a).

equipment. Thus, even if DSM savings were allocated differently, or if existing programs could be accelerated by increased personnel or effort, it is not likely that the Uxbridge substation load could be reduced to 12.5 MW in order to maintain equipment loadings within summer emergency capabilities under contingency conditions. In addition, the Siting Board notes that accelerated C&LM would not eliminate the need for additional energy resources based on double circuit outage exposure.

Based on the foregoing, the Siting Board finds that acceleration of C&LM programs could not eliminate the need for additional energy resources based on the Company's reliability criteria.

e. Conclusions on Reliability of Supply

The Siting Board has found: that the Company's criteria regarding firm service to area loads are reasonable; that the Company's criterion regarding simultaneous loss of overhead double-circuit lines is reasonable, provided that said criterion is considered in conjunction with other reliability criteria of the Company that relate to the need for two lines; and that therefore the Company's reliability criteria are reasonable for purposes of this review. The Siting Board also has found that the Company's load forecast methodology is reasonable and acceptable, and that the Company used reviewable and appropriate methods for assessing the reliability of supply based on load flow analysis.

In addition, the Siting Board has found that the Company's load flow analyses demonstrate that under 1994 peak load conditions, each of four contingencies -- the loss of the K-11/11T transmission line, the L-12/12T transmission line, the T1 transformer, and the T6 transformer -- would cause remaining equipment to be loaded above emergency summer capabilities. Further, the Siting Board has found that the supply to the Uxbridge substation currently does not meet the Company's reliability criteria in the event of the loss of the K-11/11T transmission line, the L-12/12T transmission line, the T1 transformer, or the T6 transformer. Accordingly, the Siting Board has found that there is a need for additional energy resources based on the Company's reliability criteria with regard to equipment loadings.

The Siting Board also has found: that the Company has established that supply to the Uxbridge substation does not meet the Company's reliability criteria with respect to overhead double circuit structures, considered in conjunction with other applicable criteria; and that there is a need for additional energy resources based on the Company's reliability criteria with regard to double circuit outages. Finally, the Siting Board has found that acceleration of C&LM programs could not eliminate the need for additional energy resources based on the Company's reliability criteria.

Based on the foregoing, the Siting Board finds that the Company has demonstrated that the existing supply system is inadequate to satisfy existing load supplied by the Uxbridge substation. Accordingly, the Siting Board finds that additional energy resources are needed for reliability purposes in the Uxbridge area.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, §69 H requires the Siting Board to evaluate proposed projects in terms of their consistency with providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition G.L. c. 164, §69 J requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing; (b) other sources of electrical power or natural gas; and (c) no additional electric power or natural gas.[34]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. 1991 NEPCo Decision, 21 DOMSC at 359-375; Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 18-30 (1989) ("BECo/MWRA Decision"); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985).

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[34] G.L. c. 164, §69J, also requires a petitioner to provide a description of "other site locations." The Siting Board reviews the petitioner's proposed site, as well as other site locations, in Section III.B, below.

In addition, the Siting Council has required a petitioner to consider reliability of supply as part of its showing that the proposed project is superior to alternative project approaches. 1991 NEPCo Decision, 21 DOMSC at 374-375; BECo/MWRA Decision, 19 DOMSC at 25; Massachusetts Electric Company, 18 DOMSC 383, 404-405 (1989).

2. Project Approaches

In its initial filing the Company identified two approaches to meeting the identified need (1) the proposed project -- the conversion of the Uxbridge substation supply to 115 kV by looping the Q-143, 115 kV transmission line into the substation (see Figure 2), and (2) an alternative approach -- the upgrade of the existing 69 kV system ("69 kV upgrade") (see Figure 3) (Exh. NEP-7, at 2-1, 2-6).

During the course of the proceedings one additional approach to meet the identified need was identified and evaluated. This approach is the conversion of the Uxbridge substation supply to 115 kV by tapping both the Q-143 and R-144, 115 kV transmission lines to the substation ("115 kV double tap alternative") (see Figure 4). The Siting Board's analysis of project approaches will include the proposed project, the alternative approach identified by the Company and the project approach identified during the course of the proceeding.[35]

3. Ability to Meet the Identified Need

In its analysis of the ability of each of these approaches to meet the identified need, the Siting Board evaluates whether each approach (1) would provide a reliable supply to the area served by the Uxbridge substation in the event of a loss of a transmission line or

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[35] G.L. c. 164, § 69J requires the Company to consider the alternative of "no additional electrical power." However, the Siting Board has found that the Company's existing supply system is inadequate to satisfy the existing load supplied by the Uxbridge substation (see Section II.A.3.c, above). Consequently, the Siting Board finds that the alternative of "no additional electric power" would be unable to meet the need identified in Section II.A.3.c, above. A more detailed analysis of this alternative is therefore unnecessary.

Uxbridge substation transformer, and (2) would meet the Company's double-circuit outage criteria.

a. Proposed Project

The Company asserted that the proposed project would meet the identified need (Exh. NEP-7, at 2-1, 2-6). In support thereof, the Company provided analyses of equipment loadings under the contingencies of a loss of each of the transmission lines and transformers supplying the Uxbridge substation (Exh. HO-N-16k to 16o). In its load flow analyses, the Company assumed a 23.5 MW peak load as actually experienced in 1993 and the alternative distribution configuration described in Section II.A.3.c.i, above (id.).[36] The load flow analyses demonstrate that equipment would be loaded well within emergency summer capabilities under each contingency (id.). Accordingly, the Siting Board finds that the proposed facilities would provide a reliable supply to the area served by the Uxbridge substation in the event of a loss of a transmission line or Uxbridge substation transformer.

With regard to the Company's double-circuit outage criteria, the Company stated that the Q-143 line currently is a single circuit occupying its own set of towers from the Woonsocket to the Millbury substations (Exhs. NEP-10, at 3; NEP-7, at 2-2; HO-RR-3b). The Company stated that, with the proposed looping of the Q-143 line, double circuit exposure would be limited to the Uxbridge spur ROW -- the 1.3-mile distance from the Q-143 mainline to the Uxbridge substation -- thereby reducing the likelihood of a double circuit outage (Exh. NEP-10, at 3). In addition, to protect against a double circuit outage, Mr. Browne stated that design features of the proposed transmission line would include installation of (1) a shield wire at the peak of the towers to intercept lightning strikes, and (2) a different number of insulators on each of the sides of the towers ("differential

36 The Company indicated that in 1997, the expected in-service date for the proposed facilities, the load level for the Uxbridge area is forecast to be the same as the 1993 level (Exh. HO-N-16).

insulation") (Tr. 2, at 56-57).[37] The Company indicated that differential insulation would reduce potential double circuit outages along the Uxbridge spur ROW from once per six years to once per 22 years (Exh. HO-RR-3a, at 2).[38] The Company added that a circuit breaker would be installed at the Uxbridge substation in order to electrically separate the 115 kV supply connection provided by each of the proposed lines (Exh. NEP-10, at 3). Based on the foregoing, the Siting Board finds that the proposed project would meet the Company's double-circuit outage criteria.

Accordingly, the Siting Board finds that the proposed project would meet the identified need.

b. 69 kV Upgrade

The Company asserted that the 69 kV upgrade also would meet the identified need (Brief at 11, 14). The Company stated that under the 69 kV upgrade approach, the Uxbridge substation would be supplied by both the Millbury and Woonsocket substations (Exh. NEP-7, at 2-6, 2-7). The Company stated that the existing K-11 and L-12 lines would remain at 69 kV and would be combined into a single circuit, designated as the K-11N/L-11N lines from the Millbury substation to the Uxbridge substation tap point[39] and the K-12S/L-12S lines from the Woonsocket substation to the Uxbridge substation tap point (id.).[40] See Figure 3.

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37 Mr. Browne stated that if there was a lightning strike on the shield wire, the lightning would either go to the ground, or take the line out of service by traveling along the arm of the tower across the insulators to the conductors (Tr. 2, at 56). He stated that the installation of differential insulation would cause a lightning strike to go to the side of the tower with fewer insulators, and take just one side out of service (id. at 57).

38 The Company calculated the potential double circuit outage of proposed 115 kV lines on the Uxbridge spur ROW when it first considered the 115 kV double tap alternative in 1990 (Exh. HO-RR-3a).

39 The Company explained that a tap point is where a connection is made to the circuit mainline path to supply a separate location (Exh. NEP-10, at 4).

40 The Company indicated that the existing K-11 and L-12 lines would be made into a single circuit by connecting like phases (Exh. NEP-7, at 2-6). The Company stated that the single circuit would increase the current carrying capability of the 69 kV lines (continued...)

The Company indicated that the K-11T and L-12T lines would be reconstructed to occupy single towers along the Uxbridge spur ROW (id. at 2-7; Exh. HO-A-9). The Company stated that the 69 kV upgrade also would include a new 115kV/69kV transformer at the Woonsocket substation and replacement of the two existing transformers at the Uxbridge substation with two new 69kV/13.8kV transformers (Exh. NEP-7, at 2-6). The Company noted that the two new transformers at the Uxbridge substation would be needed in order to provide adequate transformation capacity (Exh. HO-A-8).

In order to demonstrate that the 69 kV upgrade would meet the identified need, the Company provided load flow analyses assuming a 23.5 MW peak load, the alternative distribution configuration and the contingencies of the loss of the K-11N/L-12N line, the loss of the K-11S/L-12S line and the loss of one Uxbridge substation transformer (Exh. HO-A-12e to 12h). The Company indicated that there were no capacity or voltage problems associated with these load flow analyses (Exh. HO-A-12).

The Company stated that the proposed project and the 69 kV upgrade would be comparable with respect to meeting future load growth at the Uxbridge substation (Exh. HO-A-6).[41] However, the Company stated that the proposed project would address existing capacity concerns at the Depot Street and Millbury substations while the 69 kV upgrade would not address those concerns (Exh. HO-A-7).[42]

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[40](...continued)
from the Millbury and Woonsocket substations to the Uxbridge substation (id.; Exh. HO-A-8). The Company noted that the heights of some towers along the Millbury-Woonsocket ROW would be increased in order to allow the conductors to operate at a higher temperature (Exh. HO-A-10).

[41] Mr. Barys stated that the transformer ratings would be the same under both approaches but that the 115 kV line would provide more capability over a longer period of time than the 69 kV line (Tr. 1, at 76-77).

[42] Mr. Barys asserted that keeping the Uxbridge substation on the 69 kV system would accelerate the need to address capacity problems at the Depot Street and Millbury substations (Exh. NEP-10, at 4). He explained that the 7U and 8U lines would provide more contingency support to the Depot Street substation under the 115 kV option, such that, with the outage of one 115/13.8 kV transformer at the Depot Street
(continued...)

Accordingly, the Siting Board finds that the 69 kV upgrade would provide a reliable supply to the area served by the Uxbridge substation in the event of a loss of a transmission line or Uxbridge substation transformer.

With regard to a double outage, the Company indicated that, like the proposed project, double-circuit exposure would be limited to the 1.3 mile distance along the Uxbridge spur ROW, thereby reducing the likelihood of a double circuit outage (Exhs. NEP-7, at 2-6, 2-7; HO-A-9; HO-A-11). The Siting Board notes that the design features of the proposed transmission line that would protect against a double-circuit outage also could be installed in conjunction with the 69 kV upgrade. Based on the foregoing, the Siting Board finds that the 69 kV upgrade would meet the Company's double-circuit outage criteria.

Accordingly, the Siting Board finds that the 69 kV upgrade would meet the identified need.

c. 115 kV Double Tap Alternative

The Company stated that the 115 kV double tap alternative also would meet the identified need (Exh. HO-RR-3a). The Company stated that the 115 kV double tap alternative would convert the existing 69 kV K-11T and L-12T lines to 115 kV by connecting one of the tap lines to the Q-143 line and the other to the R-144 line (Exh. HO-RR-3a).[43] See Figure 4. The Company stated that, like the proposed project, the K-11T and L-12T lines would be reconductored and two new 115/13.8 kV transformers would be installed at

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[42](...continued)
substation, the remaining transformer would not exceed its summer emergency capability until the year 2003 under the proposed 115 kV option, but would exceed its summer emergency capability in 1996 under the 69 kV alternative (Exh. HO-A-7). With respect to the Millbury substation, he explained that transferring the Uxbridge load to 115 kV would make available more 69 kV capacity from the Millbury substation to service other system needs in the area (id.).

[43] The Company indicated that when the 115/69 kV transformer at the Woonsocket substation failed in 1990, a Company analysis of supply options recommended the 115 kV double tap alternative (Exh. HO-RR-3a). The recommendation was later changed to the proposed project due to concerns regarding a potential double-circuit outage on the Q-143/R-144 lines (Exh. HO-RR-3b).

the Uxbridge substation (Exh. HO-RR-7). However, the Company stated that circuit breakers would be required on both the K-11T and L-12T lines under the 115 kV double tap alternative in order to maintain the capability of the Q-143 line and R-144 line to provide reliable substation supply and to transfer power from southeastern Massachusetts/Rhode Island to central Massachusetts (Exh. HO-A-19).[44,45] During the course of the proceeding, the Company also considered the 115 kV double tap alternative with only one circuit breaker, on either the Q-143 line or the R-144 line (see Section II.B.4, below) (Exhs. HO-RR-8; HO-RR-9; HO-RR-15; HO-CL-1). The Company stated that development of a new substation at the intersection of the Millbury-Woonsocket and Uxbridge spur ROWs would be required under the 115 kV double tap alternative to accommodate either one or two circuit breakers (Exh. HO-A-19).

The Siting Board notes that by converting the existing K-11T and L-12T lines to 115 kV, installing 115/13.8 kV transformers at the Uxbridge substation and limiting double-circuit exposure to 1.3 miles along the Uxbridge spur ROW, the 115 kV double tap alternative would be comparable to the proposed project in meeting the identified need.

Based on the foregoing, the Siting Board finds that the 115 kV double tap alternative would provide a reliable supply to the area served by the Uxbridge substation in the event of a loss of a transmission line or Uxbridge substation transformer. In addition, the Siting Board finds that the 115 kV double tap alternative would meet the Company's double-circuit outage criteria.

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44 The Company indicated that, in 1994, the level of total power flow from the Woonsocket substation to the Millbury substation along the Q-143 and R-144 lines ranged from 45 MW during off-peak periods to 98 MW during peak or near-peak periods (Exh. HO-A-15).

45 In the Company's original analysis of the 115 kV double tap alternative, the Company did not include any circuit breakers on the Q-143 or R-144 lines (Exh. HO-RR-3a at 2). In that analysis, the Company indicated that the installation of differential insulation in the 115 kV lines along the Uxbridge spur ROW would reduce the potential for a double circuit outage along these lines from once in six years to once in 22 years (id. at 2-3).

Accordingly, based on the foregoing, the Siting Board finds that the 115 kV double tap alternative would meet the identified need.

d. Conclusions on Ability to Meet the Identified Need

The Siting Board has found that the Company has demonstrated that the proposed project, the 69 kV upgrade and the 115 kV double tap alternative would provide a reliable supply to the area served by the Uxbridge substation in the event of a loss of a transmission line or Uxbridge substation transformer and would meet the Company's double-circuit outage criteria. Therefore, the Siting Board has found that the proposed project, the 69 kV upgrade and the 115 kV double tap alternative would meet the identified need.

Accordingly, the Siting Board evaluates the reliability, cost and environmental impacts of the proposed project, the 69 kV upgrade and the 115 kV double tap alternative.

4. Reliability

In this Section, the Siting Board compares the proposed project with each alternative with respect to providing a reliable supply of electricity to the Uxbridge substation. In addition, the Siting Board compares the proposed project and the 115 kV double tap alternative with respect to their impact on the reliability of the Q-143 and R-144 transmission lines.

The Company asserted that the proposed project is essentially equivalent to the 69 kV upgrade with respect to providing a reliable supply of electricity to the Uxbridge substation (Brief at 12). The Company stated that the predicted average customer outage would be slightly higher for the 69 kV upgrade (0.04 minutes per year) than for the proposed project (0.02 minutes per year) based on historical outage rates which are higher for the K-11/L-12 lines than for the Q-143 line (Exhs. NEP-7, at 2-6; HO-A-4).[46] However, the Company

[46] The Company explained that the higher outage rate for the K-11/L-12 lines is due to the fact that the K-11/L-12 lines are mounted on structures that are higher than the Q-143 pole structures (Exh. HO-A-17). Therefore, the Company stated that lightning would strike the K-11/L-12 lines more often, while the Q-143 line would be shielded from lightning by the K-11/L-12 lines (id.).

maintained that, because the difference in unavailability between the two approaches is very small, the reliability of the two plans would be equivalent (Brief at 21).

Based on the foregoing, the Siting Board finds that the proposed project and the 69 kV upgrade are comparable with respect to reliability.

The Company also asserted that the proposed project and the 115 kV double tap option would be equivalent in terms of reliability of supply to the Uxbridge substation (id. at 19). However, the Siting Board notes that the two approaches would differ in their impact on the reliability of the Q-143 and R-144 lines, based on the number and location of circuit breakers that would be installed under the double tap alternative. The Company assessed the impact of the two approaches on two segments of the Q-143 and R-144 lines: (1) the segment between the Millbury substation and Whitins Pond substation, and (2) the segment between the Whitins Pond substation and the 143-4/144-4 switch, which is normally open and is located to the south of the Woonsocket substation (Exhs. NEP-7, at 2-4; HO-RR-15).[47] See Figure 4.

With respect to the proposed project, the Company indicated that a double circuit outage along the Uxbridge spur ROW would interrupt power flow along both segments of the Q-143 line, but would have no impact on the power flow along the R-144 line (Exh. HO-RR-15d).[48] With respect to the double tap alternative with one circuit breaker, the Company indicated that a double circuit outage along the Uxbridge spur ROW would interrupt power flow (1) to the same extent as the proposed project if the circuit breaker was installed on the R-144 line, and (2) to a slightly greater extent than the proposed project if

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47 The 143-4/144-4 switch is located between the Woonsocket substation and the Clarkson Street substation (Exh. HO-RR-15). The Clarkson Street substation is supplied by both the Q-143 and R-144 lines (id.).

48 The Company indicated that under this contingency, a switch between the Whitins Pond and Uxbridge substations would be opened and the line re-energized from the Millbury substation to the Whitins Pond substation within five minutes, resulting in unavailability of supply to the Whitins Pond substation of one minute/year over a five year period (Exh. HO-RR-15). Based on historical interruption data over a five year period, the Company calculated that the Q-143 line between the 143-4/144-4 switch and the Whitins Pond substation would be unavailable for 88.6 minutes per year (id.).

the circuit breaker was installed on the Q-143 line (Exh. HO-RR-15).[49] Finally, the Company's calculations indicate that, under the aforementioned contingency, power flow would not be interrupted along either segment of the Q-143/R-144 line with installation of two circuit breakers on the double tap option (Exh HO-RR-15d).[50]

Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the 115 kV double tap alternative with one circuit breaker are comparable with respect to reliability. The Siting Board also finds that the 115 kV double tap alternative with two circuit breakers would be preferable to the proposed project with respect to reliability.

5. Environmental Impacts

In this Section the Siting Board compares the proposed project to the 69 kV upgrade and the 115 kV double tap alternative with respect to the environmental impacts resulting from (1) facility construction, and (2) magnetic field levels.[51]

a. Facility Construction Impacts

In comparing the proposed project to the 69 kV upgrade, the Company stated that impacts related to transmission tower construction on the Uxbridge spur ROW for both approaches would be minor, but the need for fewer structural alterations for the 69 kV upgrade would result in less impact (Exh. HO-A-11). The Company explained that, along the Uxbridge spur ROW, (1) the 69 kV upgrade would require an increase in height of five existing towers, located in upland areas and accessible by an existing access road, and (2)

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49 Based on historical interruption data over a five year period, the Company calculated that both segments of the R-144 line would be unavailable for 88.6 minutes per year (Exh. HO-RR-15). There would be no impact on the Q-143 line (id.).

50 The Company indicated that under this contingency, there would be no outage on the R-144 line if a circuit breaker were installed on the R-144 line and no outage on the Q-143 line if a circuit breaker were installed on the Q-143 line (Exh. HO-RR-14d).

51 In this case the Siting Board focuses on magnetic field levels rather than electric field levels because perceived health impacts generally relate to magnetic field levels. See, Brief at 17-18.

that the proposed project would require replacement of three towers, and reinforcement with an increase in height of the eleven remaining towers, two of which are located in wetland areas (id.; Exh. HO-E-25b at 5).[52]

The Company added that both approaches would require tower construction along the Millbury-Woonsocket ROW (Exh. HO-A-11). The Company stated that along that ROW, the 69 kV upgrade would require an increase in the height of some towers, possibly within wetland areas, while the proposed project would require installation of two new wood structures and removal of two existing wood structures (Exhs. HO-A-10; NEP-7, at 1-2). Finally, with respect to substation construction, the Company stated that, under the 69 kV upgrade, the two new transformers would be installed at the Uxbridge substation in the same location as the existing transformers and that the physical size of both the Woonsocket substation and the Uxbridge substation would not be increased (Exh. HO-A-14). In comparison, the Company stated that the two new transformers for the proposed project would be installed in a different location at the Uxbridge substation for the proposed project, requiring some expansion of the existing fenced area (id.).

The record demonstrates that the extent of transmission line and substation construction for the 69 kV upgrade would be slightly less than that required for the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the 69 kV upgrade would be slightly preferable to the proposed project with respect to facility construction impacts.

In comparing the proposed project to the 115 kV double tap alternative, the Company stated that the extent of construction along the Uxbridge spur ROW and at the Uxbridge substation would not differ significantly for the two approaches (Exh. HO-RR-7).

However, the Company stated that the 115 kV double tap alternative would require a new substation at the intersection of the Uxbridge spur ROW and the Millbury-Woonsocket ROW in order to house circuit breaker equipment (Exhs. HO-A-16; HO-A-19). The

52 The Company noted that, in order to maintain continuous electric service during construction, the 69 kV upgrade would require the installation of five temporary poles while the proposed project would require the installation of 14 temporary poles (Exh. HO-A-11).

Company noted that the 115 kV double tap alternative also would require two additional structures at the tap location which would not be required for the proposed project (Exh. HO-CL-1).[53]

The Company stated that there was sufficient Company-owned land at this location to construct a substation for either the one circuit breaker or the two circuit breaker option (Exh. HO-RR-9).[54] The Company further stated that the maximum height of any new substation equipment would be approximately 15 feet and that screening with evergreens would be possible (Exh. HO-CL-2).[55] The Company noted that the distance from this substation location to the closest residence would be approximately 500 feet (Exh. HO-RR-9).

The record demonstrates that the extent of transmission line construction would be comparable for both the proposed project and the 115 kV double tap alternative. However, in addition to the transmission line construction, the 115 kV double tap alternative also would require construction of a new substation. Although the Company owns sufficient land for construction of a substation, the required land area is relatively small, and new substation structures could be screened, development of a new substation at this site would have potential long-term land use impacts. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the 115 kV double tap alternative with respect to facility construction impacts.

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53 The Company also considered the use of a smaller conductor in conjunction with the double tap alternative (Exh. HO-RR-8). See Section II.B.6, below. The smaller conductor would allow the Company to reuse one tower instead of replacing it with a single pole steel structure (Exh. HO-CL-1). The Company indicated that there would be no substantial difference in construction impacts if the smaller conductor were used (Tr. 1, at 61).

54 The Company noted that the land area for a new substation with two circuit breakers would be approximately 130 feet by 60 feet while 70 feet by 60 feet would be required for a substation with one circuit breaker (Exh. HO-RR-9).

55 The Company stated that the cost of screening of the substation with evergreens was not included in its cost estimate of the double tap alternative because of the low residential density in the vicinity of the substation (Exh. HO-CL-2).

b. Magnetic Field Levels

In order to compare magnetic field levels along the Uxbridge spur ROW for the three project approaches, the Company calculated magnetic field levels under expected maximum normal loading conditions at the residence closest to the ROW, at edge-of-ROW locations where magnetic field levels would be highest including the left edge of the ROW (the north side of the ROW) and the right edge of the ROW (the south side of the ROW), and at the location within the ROW where magnetic field levels would be highest (Exhs. HO-RR-10; NEP-7, at 3-2). See Table 1. In addition, the Company provided the testimony of Dr. Deborah Weil, a cell biologist who has analyzed biological responses to electromagnetic fields such as those associated with the proposed project (Tr. 1, at 107-166).

Dr. Weil testified that, although scientific organizations have examined the issue of potential health risks associated with exposure to power frequency magnetic fields in the range of the field levels of the proposed project, none has identified a particular field level as hazardous (id. at 127-128). In addition, she testified that research to date has not established "that exposure to power frequency fields, such as those associated with this project, causes cancer or other health problems" (id. at 129).

However, Mr. Barys stated that, in developing options to address a problem in reliability, the Company tries to minimize magnetic field levels (id. at 96). He stated that the Company does not have a standard for maximum magnetic field levels, but that, if in comparing two project alternatives the Company determined that all other aspects of the projects were equal, lower magnetic field levels of one alternative would be a reason to choose that alternative (id. at 96-97).[56]

With respect to the magnetic field levels of the proposed project, the Company indicated that, under the proposed project, maximum magnetic field levels would decrease from the current level of 4.01 milligauss ("mG") to 3.5 mG at the residence located closest

[56] The Company stated that it recognizes that some members of the public are concerned about magnetic field levels and for this reason, it incorporated design features into the proposed transmission lines that would reduce magnetic field levels (Brief at n.15). The Company asserted that such an approach is reasonable where field reduction can be achieved at low or no cost to customers, as was the case with the proposed project (id.).

to the ROW,[57] and from the current level of 13.8 mG to 12.4 mG at the left edge of the ROW (see Table 1) (Exhs. HO-RR-10; NEP-10, exh. FRB-7; HO-E-15a). Mr. Barys explained that the phases in the two proposed 115 kV lines, as well as two existing 13.8 kV lines which are located at the left edge of the ROW, would be arranged in order to provide as much cancellation of magnetic fields as possible (Tr. 1, at 97-98).

However, the Company also indicated that under the proposed project, magnetic field levels would increase along the right edge of the ROW, reaching a maximum of 3.4 mG, and within the ROW, reaching a maximum of 92.9 mG (see Table 1) (Exhs. HO-RR-10; NEP-10, exh. FRB-7). The Company stated that the maximum magnetic field level of 92.9 mG would occur directly under the power lines at one point where the lowest 115 kV conductor would be 23 feet above the ground, and added that an area of maximum magnetic field levels above 50 mG would occur at all locations where a 115 kV conductor would be less than approximately 30 feet above ground (Exh. HO-CL-3). The Company further stated that conductor heights in the range of 23-30 feet would occur near mid span at approximately eight locations along the ROW (id.). The Company noted that where the maximum magnetic field level would reach 92.9 mG within the ROW, magnetic field levels would decrease (1) to 11.6 mG at the pole location, 225 feet from the mid-span, and (2) to 8.7 mG at the left edge of the ROW, 63 feet away (id.). The Company noted that the land use in the vicinity of the ROW where the maximum magnetic field level would reach 92.9 mG within the ROW is open field within the ROW and low density residential use outside the ROW (id.). The Company added that the closest residence to this area is located 150 feet from the point of the maximum magnetic field (id.).

In comparing the magnetic field levels of the proposed project to the 69 kV upgrade, the Company asserted that although the magnetic field levels for the proposed project are somewhat higher, these small differences in field levels do not provide a basis for selecting one alternative over the other (Brief at 21-22). The Company noted that the differences at the closest residence are less than one mG (id.). See Table 1.

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57 The residence located closest to the ROW is located along the left edge of the ROW (Exh. HO-CL-3).

The Siting Board notes that under the 69 kV upgrade, the magnetic field levels at the closest residence, left ROW edge, right ROW edge and on the ROW would be decreased from existing levels and would be less than the magnetic field levels associated with the proposed project (Exhs. HO-RR-8; NEP-10, exh. FRB-7; HO-E-15). Although the difference between magnetic field levels at the closest residence under the two approaches would be less than one mG, the difference in magnetic field levels would be greater at the other locations, most notably within the ROW (see Table 1). Accordingly, based on the foregoing, the Siting Board finds that the 69 kV upgrade would be preferable to the proposed project with respect to magnetic fields.

In comparing the magnetic field levels of the proposed project to the 115 kV double tap alternative, the Company stated that the magnetic field levels would be higher for the proposed project than for the double tap alternative (Exh. HO-RR-10).[58] However, the Company concluded that, because magnetic field levels have not been proven to be a health hazard and there is no particular level that would be unsafe, magnetic field levels do not provide the basis for choosing one alternative over another (Brief at 18).

The record demonstrates that under the 115 kV double tap option, the magnetic field levels at the closest residence, left ROW edge, right ROW edge and on the ROW would be decreased from existing levels and would be less than the magnetic field levels associated with the proposed project (Exhs. HO-RR-8; NEP-10, exh. FRB-7; HO-E-15). Although the difference between magnetic field levels under the two approaches would be less than one mG at the closest residence, the difference in magnetic field levels would be greater at the other locations, most notably within the ROW (see Table 1). Accordingly, based on the foregoing, the Siting Board finds that the 115 kV double tap alternative would be preferable to the proposed project with respect to magnetic fields.

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[58] Mr. Barys explained that magnetic field levels along the Uxbridge spur ROW would be higher for the proposed project because magnetic field levels are related to the amount of current flowing through the line and there would be a higher current with the proposed project (Tr. 1, at 77). He stated that, for the proposed project, all the current on the Q-143 line would flow along the Uxbridge spur ROW, while for the 115 kV double tap alternative, only the current that was needed at the Uxbridge substation would flow along the Uxbridge spur ROW (id. at 77-78).

c. Conclusions on Environmental Impacts

In comparing the overall environmental impacts of the proposed project to the 69 kV upgrade, the Company asserted that there would be no significant difference between the two approaches (Brief at 21, citing, Exh. NEP-7, at 2-6). However, the Siting Board has found that the 69 kV upgrade would be slightly preferable to the proposed project with respect to facility construction impacts and preferable to the proposed project with respect to magnetic fields. Accordingly, the Siting Board finds that the 69 kV upgrade is preferable to the proposed project with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project to the double tap alternative, the Company concluded that the two approaches have essentially equivalent environmental impacts (Brief at 17-18). The Siting Board has found that the proposed project would be preferable to the 115 kV double tap alternative with respect to facility construction impacts. In addition, the Siting Board has found that the 115 kV double tap alternative would be preferable to the proposed project with respect to magnetic fields.

The Siting Board notes that the advantage of the proposed project with respect to construction impacts was based on potential long-term land use impacts associated with the construction of a new substation. However, given that: (1) the land area required for substation construction is relatively small; (2) new substation structures could be screened; (3) the nearest residence is located 500 feet from the substation site; and (4) the Company owns sufficient land for substation development, the advantage of the proposed project with respect to construction impacts is somewhat limited.

In considering the advantage of the 115 kV double tap alternative with respect to magnetic field impacts, the Siting Board notes that such advantage was based on the considerably lower field levels that would be associated with the 115 kV double tap alternative, most notably within the ROW. Although magnetic field levels would be less for the 115 kV double tap alternative at all locations considered, the magnetic field levels also would decrease from existing levels under the proposed project at two locations considered -- the residence closest to the ROW and the left edge of the ROW. Further, the difference in magnetic field levels at the residence closest to the ROW under both of the project approaches would be small.

With respect to the increase in magnetic field levels at the right edge of the ROW, the Siting Board notes that, in the Siting Council review of the Hydro Quebec project, which included 450 kV direct current and 345 kV alternating current transmission facilities, the Siting Council addressed in detail the expected electrical effects of such facilities, notably the health implications of electric and magnetic fields. Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985). In that case, the petitioner estimated that the magnetic field would not exceed 85 mG along the edge of the 345 kV ROW. Id. at 228-229. The Siting Council found those edge-of-ROW field levels to be acceptable. Id. at 241. Here, even though field levels at the right edge of the ROW would increase under the proposed project, the maximum magnetic field levels at this location would remain considerably lower than 85 mG. In addition, the field levels on the left edge of the ROW, which would be higher than those on the right edge of the ROW, also would be considerably below the 85 mG level.

Finally, with respect to the maximum magnetic field levels within the ROW, the Siting Board notes that field levels at this location would increase substantially from current levels under the proposed project and would be significantly higher than the magnetic field levels associated with the 115 kV double tap alternative. Within the ROW, the maximum magnetic field levels would reach 92 mG at one mid-span location and would exceed 50 mG at and near a number of other mid-span locations. Although the magnetic field levels are considerably reduced at the edge of the ROW, the Siting Board notes the potential for residential and recreational uses of the ROW.

The Siting Board acknowledges that the record in this case does not support a conclusion that potential health risks are associated with exposure to power frequency magnetic fields in the range of the field levels of the proposed project. The Siting Board further agrees that the Company's approach to addressing public concern -- incorporating design features into proposed transmission lines to reduce field levels where such reduction can be achieved at low or no cost to customers -- is reasonable. The Company has incorporated design features to minimize field levels at the edge of the ROW. We also suggest that the Company implement feasible and cost-effective measures to discourage access to the ROW in general.

In sum, the record demonstrates that with appropriate mitigation neither the proposed project approach nor the double tap alternative would have a clear advantage with respect to environmental impacts. The greater construction-related impacts of the 115 kV double tap alternative and greater magnetic field impacts of the proposed project can each be mitigated to some extent. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed project and the 115 kV double tap alternative are comparable.

6. Cost

The Company asserted that the proposed project would be the least-cost alternative to meet the identified need (Brief at 19, 22). In support of its assertion, the Company compared the capital cost and net present worth of revenue requirements ("NPWRR"), including line loss cost differences for the proposed project and each of the alternative approaches (Exhs. NEP-7, at 2-6, 2-8, 2-9; HO-RR-7).

In comparing the proposed project to the 69 kV upgrade, the Company stated that the capital cost of the proposed project would be greater than the capital cost of the 69 kV upgrade, but that the lower line loss costs of the proposed project would make it more economical than the 69 kV upgrade (Exh. NEP-7, at 2-8, app. B). The Company indicated that the capital cost, in 1995 dollars, would be (1) $6,500,000 for the proposed project, including $2,000,000 for transmission line work and $4,500,000 for substation work, and (2) $5,700,000 for the 69 kV upgrade, including $300,000 for transmission line work and $5,400,000 for substation work (id. at app. B-8). However, the Company stated that the NPWRR line losses with the proposed project would be less than with a 69 kV supply, providing an effective NPWRR cost savings with the proposed project (id. at 2-8, app. B).[59] The Company calculated that the cumulative NPWRR over 20 years, including incremental

[59] The Company indicated that 20-year NPWRR line loss costs would be $2.3 million less under the proposed project than under the 69 kV upgrade (Exh. NEP-7, at 2-8).

line losses,[60] would be $8,739,000 for the proposed project and $10,497,000 for the 69 kV upgrade, which is $1,758,000 or 20 percent more than the proposed project (id., at 2-8).

The Company stated that the cost advantage of the proposed project relative to the 69 kV upgrade would be even greater because the cost analysis did not include potential additional costs associated with the 69 kV upgrade including (1) costs to upgrade the existing 69 kV facilities at the Woonsocket substation,[61] and (2) costs to address capacity problems at the Depot Street substation in 1996, rather than in 2003 (see Section II.A.3, above) (Exh. NEP-10, at 4).

The record demonstrates that the proposed project has a significant cost advantage relative to the 69 kV upgrade. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the 69 kV upgrade with respect to cost.

In assessing the cost of the 115 kV double tap alternative, the Company indicated that the size of the conductor along the Uxbridge spur ROW could be smaller than under the proposed project without increasing line losses and without other disadvantages (Exh. HO-RR-8; Tr. 2, at 60-61).[62] Therefore, the Siting Board reviews the cost of the 115 kV double tap alternative for each of the circuit breaker options assuming use of the smaller conductor (see n.53, above).

In order to compare the costs of the proposed project with the 115 kV double tap alternative, the Company provided capital cost differences between the two approaches in 1995 dollars, both for the substation and transmission line (Exhs. HO-CL-1; HO-RR-8). The

60 The Company attributed a zero line loss cost to the project, and included the differences between line loss costs of the proposed project and each alternative in calculating the cost of each alternative (Exhs. NEP-7, at app. B-8; HO-RR-7e).

61 The Company noted that the 69 kV facilities have not been in service or maintained since the Woonsocket transformer failed in 1990 (Exh. NEP-10, at 4).

62 The loop design of the proposed project would require a larger conductor to accommodate bulk power transfers and power delivery to other tap points along the Q-143 line (see n.53, above). The Company indicated that a 795 thousand circular mils ("kcmil") aluminum conductor steel-reinforced ("ACSR") conductor would be used for the proposed project and that a 477 kcmil ACSR conductor would be used for the 115 kV double tap alternative (Exh. HO-RR-8; Tr. 1, at 60-61).

capital cost in 1995 dollars for the proposed project would be $6,500,000, including $2,000,000 for transmission line work and $4,500,000 for substation work, while the cost of the 115 kV double tap alternative would be (1) $7,300,000 with one circuit breaker including $1,900,000 for transmission line work and $5,400,000 for substation work, and (2) $7,550,000 with two circuit breakers including $1,900,000 for transmission line work and $5,650,000 for substation work (Exhs. NEP-7, at app. B-8; HO-CL-1).

The Company indicated that the line loss savings associated with the 115 kV double tap alternative, relative to a 69 kV supply, would be greater than those associated with the proposed project (Exh. HO-A-18).[63] The Company's analysis indicates that the cumulative NPWRR over 20 years, including incremental line loss costs, would be $9,156,000 for the 115 kV double tap alternative with one circuit breaker, which is $417,000 or five percent more than the $8,739,000 NPWRR cost of the proposed project, and $9,625,000 for the 115 kV double tap alternative with two circuit breakers, which is $886,000 or 10 percent more than the $8,739,000 NPWRR cost of the proposed project (Exhs. HO-N-7, at 2-8; HO-CL-1c).[64]

The record demonstrates that the proposed project has a cost advantage relative to the 115 kV double tap alternative with one or two circuit breakers. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the 115 kV double tap alternative with respect to cost.[65]

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63 The Company indicated that 20-year NPWRR line loss costs under the 115 kV double tap alternative would be $1,134,444 less than those under the proposed project (Exh. HO-CL-1a). The Company indicated that the proposed project would result in higher current and therefore higher line losses than the 115 kV double tap alternative along the Uxbridge spur ROW (id.; Tr. 2, at 60). See, also, n.58, above.

64 Over 30 years, the cumulative NPWRR cost of the 115 double tap alternative would be $9,669,000 with one circuit breaker and $10,198,000 with two circuit breakers -- three percent and eight percent more, respectively than the $9,400,000 NPWRR cost of the proposed project (Exhs. NEP-7 at 2-9; HO-CL-1c).

65 In making this finding, the Siting Board notes that the 115 kV double tap alternative without a circuit breaker on either the Q-143 or R-144 line would have a cost advantage compared to the proposed project with respect to capital costs and line loss (continued...)

7. Conclusions: Weighing Need, Cost, Environmental Impacts and Reliability

In comparing the proposed project to the 69 kV upgrade, the Siting Board has found that: (1) the proposed project and the 69 kV upgrade would meet the identified need; (2) the proposed project and the 69 kV upgrade are comparable with respect to reliability; (3) the 69 kV upgrade is preferable to the proposed project with respect to environmental impacts; and (4) the proposed project is preferable to the 69 kV upgrade with respect to cost.

Thus, in comparing the two project approaches, the Siting Board must weigh the environmental benefit of the 69 kV upgrade against the cost benefit of the proposed project. In assessing the environmental benefit of the 69 kV upgrade, the Siting Board has found that the 69 kV upgrade would be slightly preferable to the proposed project with respect to facility construction impacts and preferable to the proposed project with respect to magnetic fields. As noted in Section II.B.5.b, above, the preferability of the 69 kV upgrade with respect to magnetic fields was based on the lower calculated field levels at all identified locations, most notably within the ROW. In Section II.B.5.c, above, the Siting Board noted that the Company should implement feasible and cost-effective measures that would discourage access to the areas within the ROW. With such mitigation, the advantage of the 69 kV upgrade with respect to magnetic fields would be less significant. Thus, the overall environmental advantage of the 69 kV upgrade relative to the proposed project is limited.

[65](...continued)
savings. Assuming installation of a circuit breaker at the Uxbridge substation for the 115 kV double tap alternative without circuit breakers on the Q-143 or R-144 lines, the capital cost of this 115 kV double tap alternative would be $100,000 less than the proposed project due to reduced transmission line costs (Exh. HO-CL-1). In addition, the NPWRR over 20 years of line loss savings of the 115 kV double tap alternative relative to the proposed project would be $1,134,444 (Exh. HO-CL-1a). The Company questions the reliability of this alternative with respect to the interruption of power flow on both the Q-143 and R-144 lines in the event of a double outage along the Uxbridge spur ROW (see Section II.B.4, above). However, the Siting Board further notes that the Company indicated that installation of differential insulation on the 115 kV lines along the Uxbridge spur ROW would reduce the frequency of a double outage to once per 22 years (Exh. HO-RR-3a at 3).

In assessing the cost benefit of the proposed project relative to the 69 kV upgrade, the Siting Board has acknowledged that the proposed project has a significant cost advantage. As noted in Section II.B.6, above, the cumulative NPWRR over 20 years would be at least 20 percent greater for the 69 kV upgrade.

In sum, in comparing the proposed project to the 69 kV upgrade, the environmental advantage of the 69 kV upgrade is limited while the cost advantage of the proposed project is significant. Accordingly, based on the foregoing, the Siting Board finds that, on balance, the proposed project is preferable to the 69 kV upgrade.

In comparing the proposed project to the 115 kV double tap alternative, the Siting Board has found that: (1) the proposed project and the 115 kV double tap alternative would meet the identified need; (2) the proposed project and the 115 kV double tap alternative are comparable with respect to reliability; (3) the proposed project and the 115 kV double tap alternative are comparable with respect to environmental impacts; and (4) the proposed project is preferable to the 115 kV double tap alternative with respect to cost.

The record shows that the NPWRR cost disadvantage of the 115 kV double tap alternative would be greatest after a few early years of operation, and decline to less significant levels in the long run as a result of the higher level of line losses under the proposed project. The NPWRR cost of the double tap alternative is only $417,000, or five percent greater than that of the proposed project after 20 years, and only $269,000, or three percent greater after 30 years. Nonetheless, based on the Company's cost comparison using accepted methods of long-term cost analysis, the Siting Board has found a cost advantage for the proposed project.

The record also shows that the looping design of the proposed project, and the requirement that there be circuit breakers on the 115 kV double tap alternative, both are premised on the Company's perceived need to protect the 115 kV bulk power transfer capability between Woonsocket and Millbury substations from exposure to a double circuit outage arising from simultaneous faults along the two proposed lines between the Uxbridge substation and the 115 kV system. The record further indicates that the expected frequency of such a double circuit outage is once in 22 years. As discussed in Section II.A.3.a, above, the Company has not provided reliability criteria, based on the level of bulk power transfer operations or other indicators, that justify particular reliability levels for bulk power corridors.

We note that, in 1994, the actual levels of use of the bulk power transfer capability which the Company seeks to protect ranged from 45 MW during off-peak periods to 98 MW during peak or near-peak periods.[66] We further note that, if the Company were to implement the 115 kV double tap alternative without any circuit-breaker protection at the tap points, that alternative would cost $100,000 less than the proposed project, and provide 20-year NPWRR line loss savings of $1,134,000 relative to the proposed project. In addition, as discussed in Section II.B.5.b, above, a 115 kV double tap approach would result in lower magnetic field impacts than the proposed project.

Thus, to protect a bulk power transfer capability which the Company currently utilizes at a level of 45-98 MW from a contingency arising once in 22 years, the Company would incur an additional 20-year NPWRR cost of at least $1,234,000,[67] and produce greater magnetic field impacts. The Company has not identified the need for the bulk power transfers or the quantitative or other specific criteria that support its commitment to the reliability level provided for the bulk power transfers. We also note that, given that the Uxbridge substation supply would be subject to interruption under the identified double-outage contingency, the Company would incur the aforementioned higher costs and environmental impacts in order to maintain a reliability standard for the Q-143/R-144 line bulk power transfer capability that is in fact higher than the standard it is applying for serving the Uxbridge substation load.

In sum, the 115 kV double tap alternative without circuit breakers has a marginal cost and environmental advantage over the proposed project, and the Company has not supported in detail its reasons for protecting the bulk power transfer capability of the Q-143/R-144 lines by requiring circuit breakers. However, we recognize that bulk power

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[66] The Siting Board notes that such bulk power transfers may provide power needed for reliability purposes or may provide power needed for economic efficiency purposes.

[67] Additional NPWRR fixed carrying costs related to the additional $100,000 in capital cost, for example, interest and taxes, also would be incurred with the proposed project.

transfers provide regional benefits and, for the purposes of this review, accept the Company's judgment that those benefits outweigh marginal cost and environmental benefits. In the future, applicants will be required to provide quantitative or other specific criteria to support all reliability objectives on which they rely in designing and choosing between project alternatives.

Based on the foregoing, the Siting Board finds that, on balance, the proposed project is preferable to the 115 kV double tap alternative.

III. Analysis of the Proposed and Alternative 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 its review of other site locations, 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. Cabot Power Corporation, 2 DOMSB 241, 371 (1994) ("Cabot Power Decision"); Boston Edison Company (Phase II), 1 DOMSB 1, 35 (1993) ("1993 BECo (Phase II) Decision"); 1991 NEPCo Decision, 21 DOMSC at 376.

A. Description of the Proposed Facilities and Alternative Facilities

1. Proposed Facilities

NEPCo proposes to construct two 115 kV transmission lines that would loop NEPCo's existing Q-143 line, a 115 kV transmission line which is located within NEPCo's Millbury-Woonsocket ROW, into the Uxbridge substation (Exhs. NEP-7, at 2-1; NEP-11, at 3). The proposed transmission line along the primary route would be located within the Town of Uxbridge and would be placed within an existing electric utility ROW for its entire route (Exh. NEP-12). The primary route for the transmission line would begin at the intersection of the Uxbridge spur ROW and the Millbury-Woonsocket ROW and would travel in a northeast direction, within the Uxbridge spur ROW, for 1.3 miles to the Uxbridge substation (Exhs. NEP-7, at 1-1; NEP-11, at 2-3). The primary route would cross the Providence and Worcester Railroad, State Route 122, and two local roadways (Exhs. NEP-4; NEP-8, exh. C). See Figure 5.

The Uxbridge spur ROW is 165 feet wide and is currently occupied by two 69 kV transmission lines, the K-11T and L-12T lines,[68] and two 13.8 kV distribution lines (Exhs. NEP-7, at 3-16; NEP-10, at 4). The 13.8 kV distribution lines are located between the K-11T and L-12T lines and the north (left) edge of the ROW (Exhs. NEP-7, at 3-16; NEP-8, exh. C).

In order to construct the proposed 115 kV transmission line along the primary route, the Company stated that it would convert the existing 69 kV transmission lines to 115 kV by replacing the existing conductor with a 795 kcmil ACSR conductor (Exh. NEP-11, at 2-3). The Company stated that in order to accommodate the new conductor and to allow for operation at 115 kV, it would modify or replace the fourteen existing steel lattice towers as follows: (1) reinforce eleven existing towers; (2) increase the height of three of those eleven towers by three feet and eight of those towers by eight feet; and (3) remove and replace the three remaining towers with six single-circuit, single-shaft wood pole structures and one double-circuit, single-shaft steel pole structure (id. at 3).[69] The Company indicated that the proposed tower and pole structures would range in height from 79 feet to 90 feet and that the average structure spacing would be approximately 500 feet (id.). The Company noted that two existing wood pole structures on the Q-143 line also would be replaced with new two-pole wood structures (id.).

In addition, the Company's proposal includes the installation of two new 115/13.8 kV transformers at the Uxbridge substation, requiring some expansion of the existing fenced area of the substation (Exhs. NEP-7, at 2-1; HO-A-14).

2. Alternative Facilities

The Company proposed two alternative routes -- Alternative Route B, a 1.8 mile overhead route and Alternative Route G, a 1.7 mile underground route (Exh. NEP-7,

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68 As noted in Section II.A.2, above, the K-11T and L-12T lines are supported on single structure double circuit steel towers (Exh. NEP-10, at 3).

69 In addition, the Company stated that it would construct temporary poles to house the 69 kV line while construction was in progress in order to maintain service (Exh. NEP-7, at 3-15).

at 3-17, 3-18). Both alternative routes also are located within the Town of Uxbridge and would extend from the Millbury-Woonsocket ROW to the Uxbridge substation (id. at 3-8).

From a point on the Millbury-Woonsocket ROW to the southeast of its intersection with the Uxbridge spur ROW, Alternative Route B would travel east along 0.9 miles of new ROW across private land, then turn to the north for 0.8 miles along the Providence and Worcester railroad ROW[70] and then turn to the east to follow a 0.1 mi section of the Uxbridge spur ROW to the Uxbridge substation (id. at 3-3, 3-17). Alternative Route B would cross the Providence and Worcester Railroad ROW, State Route 122, State Route 146, one local roadway, and a tributary to the Blackstone River (id. at 3-8, 3-23). See Figure 5. The Company indicated that two single-circuit 115 kV lines would be installed on single-shaft poles with davit arms (id. at 3-17). The Company noted that the steel poles, approximately 95 feet in height, would be used along the railroad ROW and that wood and steel poles, approximately 75 feet in height, would be used along the new ROW across private land (id.).

From a point on the Millbury-Woonsocket ROW to the northwest of its intersection with the Uxbridge spur ROW, Alternative Route G would travel underground, 1.4 miles to the west along High Street, then turn to the south for 0.1 miles along State Route 122, and then turn to the east along a 0.2 mile section of the Uxbridge spur ROW (id. at 3-8, 3-9). See Figure 5. The Company indicated that Alternative Route G would consist of (1) two underground 115 kV, high pressure, gas-filled, pipe-type cables that would be installed in a four-foot wide by five-foot deep trench, and (2) two transition stations,[71] one at the Uxbridge substation and one near High Street on the Millbury-Woonsocket ROW (id. at 3-17). The Company indicated that a three-inch diameter, polyvinylchloride conduit for communication and relaying requirements also would be installed in the trench (id.).

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70 The Company indicated that poles would be constructed on both sides of the railroad tracks (Exh. NEP-7, at 3-18).

71 The Company explained that a transition station consists of specialized equipment required to transfer the wires from overhead to underground (Tr. 2, at 52). Each transition station would require approximately 0.25 acres of fenced area to isolate equipment (Exh. NEP-7, at 3-17).

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. Cabot Power Decision, 2 DOMSB at 373; 1991 NEPCo Decision, 21 DOMSC at 376; Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987) ("NEA Decision"). 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. Cabot Power Decision, 2 DOMSB at 373; 1991 NEPCo Decision, 21 DOMSC at 376-377; Berkshire Gas Company (Phase II), 20 DOMSC 109, 148-149, 151-156 (1990). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity. Cabot Power Decision, 2 DOMSB at 373; 1991 NEPCo Decision, 21 DOMSC at 379; NEA Decision, 16 DOMSC at 381-409.

In the sections below, the Siting Board reviews the Company's site selection process, including NEPCo's development and application of siting criteria as part of its site selection process.

2. Development of Siting Criteria

a. Description

The Company indicated that, in order to investigate potential routing options for the proposed transmission line, it first identified a study area that would encompass all viable routing options between the Uxbridge substation and the Millbury-Woonsocket ROW (Exh. NEP-7, at 3-1). The Company indicated that the potential study area in the vicinity of the Uxbridge substation and the Millbury-Woonsocket ROW was limited in size due to land use and topographical features that would preclude transmission line routing (id.; Tr. 2, at 25). The Company stated that the specific study area was selected based on a field visit and review of areas maps, and includes the area bounded by: (1) the commercial area of Uxbridge Center to the north; (2) an existing 345 kV transmission line ROW to the south; (3) the Providence and Worcester railroad ROW to the east; and (4) the Millbury-Woonsocket ROW to the west (Exh. NEP-7, at 3-1; Tr. 2, at 25).

In order to identify potential routes within the selected study area, the Company stated that it next established two types of siting criteria (1) opportunities -- factors which favor the placement of a transmission line by minimizing potential impacts, and (2) constraints -- factors which could be adversely affected by routing of a transmission line (Exh. NEP-7, at 3-1). The Company stated that routing opportunities consist of existing active and abandoned utility and transportation corridors (id. at 3-1, 3-3, 3-4). The Company explained that generally, constraints relate to environmental impacts, construction difficulties and licensability (id. at 3-1, 3-3).[72] The Company identified 25 constraints and classified each as high, medium or low level based on its significance for or impact on routing (id., at 3-1, 3-4; Exh. HO-S-3; Tr. 2, at 19-20).[73]

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72 The Company stated that the list of environmental constraints was developed based on the Company's experience with environmental issues associated with similar transmission line studies in the Northeast and was compiled by a group that included transmission engineers and environmental and land use specialists (Exh. HO-S-3; Tr. 2, at 19).

73 The Company explained that: (1) routes with high level constraints should be used only where circumstances preclude avoidance; (2) routes with medium level constraints should be used only in areas where circumstances precludes the use of routing opportunities, areas without constraints or areas with low level constraints; and (3) routes with low level constraints should be used only in areas where circumstances preclude the use of routing opportunities or areas without constraints (Exh. NEP-7, at 3-1, 3-3).

Constraints classified as high include: (1) home relocation; (2) sensitive cultural or historical resource; (3) federal or state endangered or threatened species location; (4) significant wildlife habitat; (5) significant natural plant community; (6) non-spannable lake, reservoir or river; and (7) cemetery (id. at 3-4). Constraints classified as medium include: (1) navigable airspace around airport; (2) medium to high density residential area, school or business adjacent to edge of ROW; (3) recreation area; (4) federal and state park/forest/other dedicated land; (5) very (continued...)

Using information from state and local agencies and field reconnaissance, the Company then identified and mapped the specific constraints and opportunities that exist within the selected study area (Exh. NEP-7, at 3-3). The Company indicated that the specific constraints in the study area include: (1) sensitive cultural or historical resources, significant wildlife habitat and a cemetery, classified as high level; (2) non-spannable wetlands,[74] medium/high density residential area, recreation areas, Federal and State Park/forest/dedicated land, and very erodible soils, classified as medium level; and (3) active farmland, spannable river and wetland, woodlands, aquifer, 100-year floodplain, road or railroad crossing, and low density residential area, classified as low level (id. at 3-5 to 3-7). The Company indicated that specific routing opportunities in and near the study area included: (1) the Uxbridge spur ROW and the Millbury-Woonsocket ROW; (2) a 345 kV transmission line ROW; (3) a gas pipeline ROW; (4) the Providence and Worcester Railroad ROW; and (5) roadways (id. at 3-7).

Assuming a 120-foot wide ROW,[75] the Company then identified six potential overhead routes following existing utility and/or transportation corridors for at least part of the route, and one potential underground route along public roads (id. at 3-3, 3-8, 3-9).[76]

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[73](...continued)
erodible soil; (6) major ridgeline; (7) wildlife refuge; (8) scenic area/road; and (9) conservation/watershed protection land (id.). Constraints classified as low include: (1) active farmland or agricultural district; (2) spannable lake, reservoir, river or wetland; (3) woodland; (4) aquifer or aquifer protection district; (5) 100-year floodplain or floodplain protection district; (6) erodible soil; and (7) low density residential area adjacent to the edge of the ROW (id.).

[74] The Company defined a non-spannable wetland as greater than the typical span length of 700 feet of the proposed transmission line (Exh. NEP-7, at 3-5).

[75] The Company noted that a 120-foot ROW, which is the width of the Company's normal ROW for two 115 kV lines constructed using single-pole davit-arm structures, would provide adequate clearances for the safe operation and maintenance of its lines (Exh. HO-S-5).

[76] The Company indicated that it did not find an acceptable overhead transmission line route on public streets because such a line would: (1) be difficult to bring into compliance with required clearances; (2) require significant tree trimming and removal
(continued...)

The Company noted that all routes, with the exception of the primary route, would require land rights acquisition (id. at 3-3).

In order to assess the environmental impacts of the seven identified routes, the Company assigned a weighting factor to each of the constraints and opportunities used to identify the routes (id., at 3-10, 3-12, 3-13).[77] The Company stated that the weights reflected the importance of the constraint in the study area and indicated that generally the weights were higher for high level constraints than low level constraints, ranging from 1.5 for low level constraints such as road/railroad crossing and 100-year floodplain to 7.5 for high level constraints such as sensitive cultural/historical resources and significant wildlife habitat (id. at 3-5, 3-6, 3-13; Tr. 2 at 29, 36). However, the Company noted that the weight for a specific constraint category was not dependent on its classification as a high, medium or low level constraint and that the weights for specific low level constraints could be higher or equal to the weight for specific medium level constraints (id. at 3-13). In addition, the Company assigned a weight of 19 to the opportunity of existing utility/transportation corridors (id. at 3-13). The Company explained that weight for this category was determined in the same way as weight factors for the environmental constraints and then doubled to reflect the importance of avoiding the creation of new utility corridors in transmission line routing (id.; Tr. 2, at 32-33).[78]

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[76](...continued)
along public streets; (3) have greater impact than construction along other evaluated routes; and (4) have decreased reliability due to greater potential for vehicular damage (Exh. NEP-7, at 3-9).

[77] Mr. Browne stated that weights represent an average of weights assigned individually by a group that included two transmission line engineers, a land-use specialist and a natural resources specialist (Tr. 2, at 26-27).

[78] The Company noted that, for this particular case, the weight was the same for all types of existing corridors within the study area, i.e., use of an existing utility ROW had the same weight as use of an existing railroad ROW (Exh. NEP-7, at 3-13; Tr. 2, at 33-34). The Company explained that the type of existing corridor would not be significant from an environmental perspective, but that the type of existing corridor could affect cost and reliability (Tr. 2, at 33-34).

The Company also assessed the seven identified routes based on costs and reliability (Exh. NEP-7, at 3-12). In preparing a cost estimate for each of the identified routes, the Company included the cost of the transmission line materials and construction, engineering, licensing, and ROW acquisition (id.). The Company also considered the impact of line losses on the cost of the identified routes (id.). With respect to reliability, the Company computed the minutes per year of unavailability ("UA") for each identified route based on: (1) the type of construction (overhead or underground); (2) the total of line length exposure; (3) the mean time between failures; and (4) the mean time to repair (id.).

b. Analysis

The Company has developed a set of site selection criteria that include the general categories of land use compatibility, physical and topographical constraints, environmentally sensitive areas, cost and reliability -- general categories that the Siting Council has found to be appropriate for the siting of transmission lines. See, 1991 NEPCo Decision, 21 DOMSC at 386. After selecting an area that would encompass all viable routing options, the Company identified a comprehensive list of the specific environmental criteria that exist within this area in order to identify and evaluate potential routes. The Company also appropriately assigned weights to the specific environmental criteria that were based on the importance of these criteria. In addition, the Company's weighting of environmental factors appropriately stresses the importance of siting transmission lines within existing corridors where possible.

The Company provided a separate analysis of the cost and reliability of each identified route and adequately explained the factors that were considered in preparing the cost and reliability analyses. However, the Company did not fully explain how cost and reliability were considered in the identification of potential routes. Further, although the Company's weighting methodology provides for a quantitative comparison among competing environmental criteria, the Company did not provide overall weights for the cost, environmental impact and reliability categories and thus, did not explain how it would balance the potentially competing criteria of cost, environmental impact and reliability.

Here, the reliability of all identified routes is essentially the same, and the primary route has the lowest environmental impact and lowest cost (see Section III.C.3.c.3, below). Therefore, in this case, the balancing of cost, environmental impact and reliability is not essential. However, in future reviews, applicants should provide overall weights for the categories of cost, environmental impact and reliability or fully explain how they would balance potentially competing cost, environmental impact and reliability criteria.

Accordingly, based on the foregoing the Siting Board finds that the Company has developed a reasonable set of criteria for identifying and evaluating alternative routes.

3. Application of Siting Criteria

a. Description

In order to evaluate the seven identified routes, the Company ranked the routes in three separate categories -- environmental impact, cost and reliability (Exh. NEP-7, at 3-9 to 3-12). With respect to environmental impact, the Company indicated that it applied its environmental criteria to the identified routes using a two-step paired analysis (id.). The Company asserted that for this case, where the study area was small and fairly homogeneous and where many of the environmental constraints and opportunities were applicable to all the routes, a paired analysis rather than a quantitative analysis of each individual route was the best technique to differentiate the routes and establish their relative rankings (Exh. HO-S-4; Tr. 2, 34).

The Company first performed an unweighted paired analysis which compared each route to each other route for each environmental criterion (Exh. NEP-7, at 3-9 to 3-11). To perform the unweighted paired analysis, the Company compared each route to each of the other routes for each environmental category, by scoring a "one" to the route with the least impact and a "zero" to the route with the greater impact (id.). The Company stated that scores were based on "judgments ... regarding which route would have the least impact on each constraint and would maximize the use of each opportunity" (id. at 3-9). The Company then computed an overall score for each route for each category by totalling the comparative scores within each category (id. at 3-10). Thus, scores for each route for each category ranged from zero to six and a route that received a score of "six" (i.e., a "one" when compared to each other route) would have the least impact in that category as compared to the other routes (id.).

As the second step of its analysis, the Company used the results of the unweighted paired analysis to perform a weighted analysis (id. at 3-10 to 3-12). The Company computed a weighted value for each environmental constraint and opportunity for each route by multiplying the weight factor derived for each environmental constraint and opportunity by the unweighted total (id.). The Company then added together the weighted values for each environmental constraint and opportunity to derive the total score for each route with a higher score signifying lower environmental impact (id. at 3-11, 3-12). However, the Company noted that this assessment provided an approximate assessment of the environmental impacts of the identified routes and that small disparities in total scores did not signify a difference in overall environmental impacts (id. at 3-12).

The Company identified three groups of routes based on their environmental impacts (id.). The Company identified two routes as having the least environmental impact, including the primary route, with a score of 350, and Alternative Route G, with a score of 328 (id.). The Company identified four routes, with scores ranging from 123 to 144, as falling in the middle range of environmental impacts, including Alternative Route B with a score of 134 (id.). The Company identified one route, with a score of 80, as having the greatest environmental impact (id.).

The Company next compared the identified routes on the basis of cost (id.). The Company prepared cost estimates of each of the routes which included the cost of line materials and construction, engineering, licensing, and ROW acquisition (id.). The Company indicated that cost estimates ranged from $2.0 million for the primary route to $5.7 million (id.). The Company further indicated that Alternative Route B was the second least expensive route at $3.2 million and that Alternative Route G was one of the most expensive routes at $5.4 million (id. at 3-12, 3-14).[79]

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79 The Company noted that the primary route would have the lowest line losses among all routes because it was the shortest in length (Exh. NEP-7, at 3-12). The Company further noted that inclusion of losses would have only a slight impact on the relative cost of the study routes (id.).

The Company also compared the six routes with respect to reliability based on the calculated "UA" for each route (id. at 3-12). The Company concluded that the UA of all routes was essentially zero and that, therefore, there was no difference in reliability between the routes (id.).

Based on the results of the environmental, cost and reliability analyses, the Company selected three alternative routes for further evaluation: the primary route, Alternative Route B, and Alternative Route G, which are described in Sections III.A.1 and 2, above.

The Company stated that the primary route was selected because it had low environmental impacts and the lowest cost (id. at 3-12). With respect to the selection of an alternative route, the Company stated that the route selection process did not identify a route that was clearly second-best (id.). Therefore, in order to evaluate a full range of alternatives, the Company compared the primary route with two alternative routes with significantly different characteristics. The Company noted that Alternative Route B has the second lowest cost but greater environmental impacts than the primary route or Alternative Route G and that Alternative Route G has essentially the same environmental impacts as the primary route but significantly higher cost than the primary route or Alternative Route B (id.).

In a response to a Staff request, the Company also conducted a paired analysis incorporating only the three routes selected for further consideration -- the primary route, Alternative Route B and Alternative Route G (Exh. HO-S-6). The relative scoring in the three route analysis-- 69.75 for the primary route, 67.75 for Alternative Route G, and 8.0 for Alternative Route B -- was comparable to the results of the Company's original paired analysis of all seven routes (id.; Exh. NEP-7, at 3-13).

b. Analysis

In this Section, the Siting Board examines whether NEPCo applied its siting criteria to its siting options in a consistent and appropriate manner that ensured that no clearly superior routes were overlooked or eliminated.

The record demonstrates that the Company identified and evaluated a considerable number of potential routes within a specified area based on a comprehensive set of criteria.

To evaluate the routes with respect to environmental impacts, the Company compared each route to each other route for each environmental criterion and incorporated a quantitative scoring and weighting methodology.

Although the Company developed a numerical score for each route for each environmental criteria based on the Company's judgment as to which route would involve the least environmental impact or the maximum use of opportunity, the Company did not fully explain how such judgments were made. For instance, for the environmental constraint of "school/business/medium-high density residential," the Company did not specify whether or how its judgment of least environmental impact reflected more specific factors relevant to that category, such as distance from buildings, number of buildings, or use of buildings. Likewise, for the environmental constraint of "woodland," the Company did not specify how or whether its judgments reflected more specific factors such as woodland type or length of route through woodland. In future filings, applicants should fully explain the basis for judgmental scoring of routes including any specific factors that affected the judgments.

Nevertheless, the Company performed a comprehensive quantitative comparison of the identified routes based on weighted environmental criteria as well as quantitative cost data. Thus, in evaluating routes, the Company applied its siting criteria in a consistent manner.

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

The Siting Board has found that the Company has developed a reasonable set of criteria for identifying and evaluating alternative routes and that the Company has applied its site selection criteria consistently and appropriately and in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to the proposal.

Accordingly, based on the foregoing, the Siting Board finds that the Company 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.

4. Geographic Diversity

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

The Company considered three different routes for the proposed transmission line. Although the three routes overlap for a short distance when entering the Uxbridge substation,[80] the routes are clearly distinct. They each start at a different point along the Millbury-Woonsocket ROW and travel along a different corridor, each terminating at the Uxbridge substation. In addition, in considering both underground and overhead routes, and different types of corridors (an existing transmission line ROW, roadways, and a railroad ROW/new ROW), the Company considered routes with significantly different characteristics.

Based on the foregoing, the Siting Board finds that the Company has identified three practical routes that are geographically diverse.

5. Conclusions on the Site Selection Process

The Siting Board has found that the Company 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. In addition, the Siting Board has found that the Company has identified at least two practical routes with some measure of geographical diversity.

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

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80 All routes overlap for a distance of 0.1 miles along ROW from the railroad ROW to the Uxbridge substation (Exh. NEP-7, at 3-8, 3-17). In addition, the primary route and Alternative Route G overlap for an additional 0.01 miles from Route 122 to the railroad ROW (id.).

C. Environmental Impacts, Cost and Reliability of the Proposed and Alternative 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 (Phase II) Decision, 1 DOMSB at 37-38; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

An 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. Cabot Power Decision, 2 DOMSB at 389; Eastern Energy Corporation, 22 DOMSC 188, 334, 336 (1991) ("EEC Decision"). A facility which achieves that appropriate balance thereby meets the Siting Board's statutory requirement to minimize environmental impacts at the lowest possible cost. Cabot Power Decision, 2 DOMSB at 389; EEC Decision, 22 DOMSC at 334, 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. Cabot Power Decision, 2 DOMSB at 389; EEC Decision, 22 DOMSC at 334, 336. The Siting Board previously has found that 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. Cabot Power Decision, 2 DOMSB at 389; 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 review must be clearly described and consistently applied 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. Cabot Power Decision, 2 DOMSB at 389-390; 1993 BECo (Phase II) Decision, 1 DOMSB at 39-40. The Siting Board can then determine whether environmental impacts would be 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 would be achieved. Cabot Power Decision, 2 DOMSB at 390; 1993 BECo (Phase II) Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental and cost related impacts of the proposed facilities at the Company's primary and alternative routes to determine (1) whether environmental impacts would be minimized along each route, and (2) whether an appropriate balance would be achieved along each route among conflicting environmental concerns as well as between environmental impacts and cost.[81] In this examination, the Siting Board then conducts a comparison of the primary and alternative routes to determine which is preferable with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

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81 The Company indicated that there was no difference in the reliability between the primary and alternative routes (Exh. NEP-7, at 3-12). See Section III.B.3.a, above.

2. Analysis of the Proposed Facilities along the Primary Route

a. Environmental Impacts of the Proposed Facilities along the Primary Route

In this Section, the Siting Board evaluates the environmental impacts of the proposed facilities along the primary route and potential mitigation for such impacts, including the proposed mitigation and, as necessary, any identified options for additional mitigation. As part of its evaluation, the Siting Board addresses whether the petitioner has provided sufficient information for the Siting Board to determine (1) whether environmental impacts would be minimized, and (2) whether the appropriate balance among environmental impacts and among environmental impacts, cost and reliability would be achieved. The Siting Board also addresses whether the environmental impacts of the proposed facilities along the primary route would be minimized.

i. Water Resources

(A) Wetlands and Surface Water

The Company asserted that construction of the proposed facilities along the primary route would have no adverse impact on the freshwater wetlands on and near the primary route (Exh. NEP-7, at 3-21). Based on field surveys, the Company identified four shrub-emergent, bordering vegetated wetlands along the existing ROW (id. at 3-20).[82] The Company added that the length of wetland crossings would vary from approximately 15 feet to 475 feet and would total approximately 720 feet (id. at 3-21).

The Company indicated that two existing towers would be reinforced within the largest wetland area along the route, identified as Wetland #4, located between Route 122 and the Providence and Worcester railroad ROW (Exhs. HO-E-25b, at 5; HO-E-20, att.). The Company indicated that both of the towers are located near the edge of Wetland #4; one of the towers is located close to Route 122 and the other is located close to the Providence and Worcester railroad ROW (Exh. HO-E-20, att.). NEPCo stated that access to the two towers

82 The Company stated that there were also forested "bordering vegetated wetlands," associated with the ROW wetlands, along the edges and within 100 feet of the ROW (Exh. NEP-7, at 3-21).

would be from existing access roads and the Providence and Worcester railroad ROW, if possible (Exh. NEP-7, at 3-21; Tr. 2 at 39-40). NEPCo added that if access through wetlands is necessary, swamp mats or temporary gravel roads would be used to reduce the effect of any vehicular traffic on wetland vegetation and substrate and that no permanent access roads would be maintained within wetlands (Exh. NEP-7, at 3-21; Tr. 2 at 41). In addition, the Company stated that all disturbed surface wetland soil would be restored and that erosion and sedimentation control devices would be used to protect wetland areas (Exh. NEP-7, at 3-21).[83]

With respect to surface water, the Company indicated that the primary route crosses a tributary of the Blackstone River which borders the southern edge of Wetland #4 and which is comprised of two small headwater streamlets on the ROW that become one stream south of the ROW (Exhs. NEP-7, at 3-22, 3-23; HO-E-20, att.). In addition, the Company stated that, during its field surveys, it identified two additional streamlets associated with wetlands located along the ROW (Exh. NEP-7, at 3-23).[84] The Company asserted that construction of the proposed facilities along the proposed route would have little impact on any of these streamlets (id.). NEPCo stated that construction equipment would use an existing access road that fords the streamlets and that construction would include stream protection measures to reduce disturbance and sedimentation of all streams (id.). The Company further stated that construction would not alter the ROW terrain or local drainage patterns (id.).

The record demonstrates that construction of the proposed facilities along the primary route would require a minimal amount of construction within wetland areas and in the vicinity of surface water. Further, the Company would use existing access roads where possible and would use appropriate mitigation measures. Based on the foregoing, the Siting Board finds that, with the utilization of the proposed mitigation measures in wetland areas

83 The Company indicated that proposed work in wetland areas would be subject to an Order of Conditions under the Wetlands Protection Act (Exh. NEP-7, at 3-21).

84 The Company indicated that of the four streamlets that were identified along the primary route, two had flowing water with a maximum depth of 6 inches, one streamlet bed had intermittent patches of water and one streamlet bed was dry (Exh. NEP-7, at 3-23).

and around stream beds, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to wetlands and surface water.

(B) Groundwater and Wells

The Company asserted that construction of the proposed facilities along the primary route would not impact the Blackstone River aquifer or the Town of Uxbridge's existing or proposed well fields (Exh. NEP-7, at 3-24). The Company stated that the primary route crosses a 0.3-mile section of the Blackstone River aquifer, an underground water supply source in Uxbridge, which extends from the Uxbridge substation to a short distance west of Route 122 (id.). In addition, the Company stated that the Town of Uxbridge's well fields are located approximately 1,000 feet to the southeast of the Uxbridge substation and that a proposed well field is located along the Blackstone River, approximately 1.9 miles to the south of the primary route (id.; Exh. HO-E-7b).

The Company stated that the existing well fields are located within the 100-year floodplain area and the Groundwater Protection Overlay District of the Town's zoning bylaw (Exh. HO-E-7b). The Company indicated that the Uxbridge substation and 400 feet of the primary route also are within the 100-year floodplain and that approximately 1700 feet of the primary route is located within the Groundwater Protection Overlay District (Exh. HO-E-7b).[85]

The Company indicated that no herbicides would be used in clearing or trimming vegetation from the primary route as part of the construction of the proposed facilities (Exh. HO-E-3). However, the Company stated that the use of herbicides is an integral part of NEPCo's vegetative management program for existing ROWs and that herbicides were

[85] The Company provided a copy of the Zoning Bylaw of the Town of Uxbridge that establishes groundwater protection districts, "consisting of municipal wellfields, aquifers and/or aquifer recharge areas" (Exh. HO-E-2a, sec. XIX). The Zoning Bylaw prohibits specific uses in such districts without a special permit, and allows all uses allowed by underlying Zoning Regulations (id. at sec. XIX.3.A, sec. XIX.3.B). The Company stated that since public utility uses are not permitted uses in the underlying districts, they would not be permitted uses in the groundwater protection district (Exh. HO-E-2b). Thus, the Company has requested that the Department grant an exemption from this section of the Zoning Bylaw (Exh. NEP-9; D.P.U. 94-182).

used on the Uxbridge spur ROW in 1986 and in 1991 and likely would be used again in 1996 or 1997 (id.; Exh. HO-E-4). NEPCo indicated that herbicides will be applied in compliance with 333 CMR 11.00 which prohibits application of herbicides within 400 feet of municipal water supply wells and in accordance with commitments made to the Town of Uxbridge in 1991 (Exh. HO-E-26). The Company stated that in 1991 Uxbridge officials raised questions regarding herbicide use near public water supplies and that in response, the Company has agreed to expand the no-herbicide zone surrounding public wells beyond the 400-foot radius, extending it to the entire portion of the route between the Uxbridge substation and Route 122 (id; Exhs. HO-E-5a, at 17-23; HO-E-6).[86]

With respect to the transformer replacement at the Uxbridge substation, the Company provided documentation from the Massachusetts Department of Environmental Protection ("MDEP") that the Uxbridge substation is located within a designated aquifer recharge area, known as the Zone II area for Uxbridge's Bernat Wells (Exh. HO-RR-11). The MDEP indicated that, in order to protect said wells, the Company should minimize the possibility of spills from the transformers during transformer replacement and that preparation of an emergency response plan prior to transformer replacement may be warranted (id.).[87]

The record demonstrates that a portion of the primary route crosses both the aquifer used for the Town of Uxbridge's water supply and the Town of Uxbridge's Groundwater Protection Overlay District and that the Uxbridge substation is located within a Town well area. The Company has responded to concerns of the Town regarding use of herbicides near public water supplies by limiting herbicide use along the portion of the Uxbridge spur ROW between the Uxbridge substation and Route 122. The Siting Board notes that the boundary of the aquifer extends a short distance beyond Route 122; however, the record does not

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86 The Siting Board notes that the aquifer boundary extends a short distance to the west of Route 122 (Exh. HO-E-20, att.).

87 In the Certificate on the Company's Environmental Notification Form, which determined that an Environmental Impact Report was not required for the proposed project, the Secretary of Environmental Affairs suggested that the Town of Uxbridge require the Company to prepare an Emergency Response Plan to ensure protection of the town's water supply in the event of transformer replacement within Zone II (Exh. HO-RR-11).

specify whether the herbicide limitation extends to the boundary of the aquifer or to Route 122. The Siting Board suggests that the Company also limit or avoid herbicide application within the portion of the ROW between Route 122 and the boundary of the aquifer. In addition, the Siting Board suggests that the Company prepare an Emergency Response Plan to address possible spills during the transformer replacement at the Uxbridge substation.

Based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to groundwater and wells.

(C) Conclusions

The Siting Board has found that (1) with the utilization of the proposed mitigation measures in wetland areas and around stream beds, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to wetlands and surface water, and (2) the environmental impacts of the proposed facilities along the primary route would be minimized with respect to groundwater and wells. Accordingly, based on the foregoing, the Siting Board finds that, with the utilization of the above noted mitigation measures, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to water resources.

ii. Land Resources

In this Section, the Siting Board reviews the impact of the proposed facilities along the primary route with respect to tree clearing and upland vegetation, potential soil erosion and wildlife habitat. With respect to tree clearing and vegetation, the Company stated that construction of the proposed transmission line along the primary route would not require additional ROW acquisition or clearing (Exh. HO-E-25b, at 1). The Company indicated that the existing ROW has been adequately maintained in the past and that, therefore, only minimal tree trimming would be required during construction (Exh. NEP-7, at 3-15, 3-26). The Company added that ongoing maintenance of the ROW would sustain existing vegetative conditions (id. at 3-26). The Company noted that there are no rare or endangered plant species or natural communities in the vicinity of the primary route (Exh. HO-E-25b).

With respect to potential soil erosion, the Company indicated that the proposed facilities along the primary route would be constructed along slopes and would cross areas that are susceptible to soil erosion (Exh. NEP-7, at 3-27). However, the Company stated that erosion protection measures, including hay bales, siltation fences, seeding and mulching would be used to prevent erosion and sedimentation along the route (id.).

Finally, the Company noted that two state wildlife species of special concern exist in the proximity of the primary route, one confined to a wetland and aquatic habitat approximately one-half mile to the south of the primary route and one that could occur in many habitats (Exh. HO-E-25b).[88] The Company stated that construction of the proposed facilities along the primary route would not impact either species (id.).

The record demonstrates that construction of the proposed facilities along the primary route would not require tree clearing and would not change the existing vegetative conditions along the ROW. In addition, the record demonstrates that erosion control measures would be used during construction to prevent erosion and sedimentation along the ROW. With respect to wildlife habitat, the Siting Board notes that short-term disruption could occur during facility construction. However, due to the maintenance of existing vegetative conditions, erosion control measures and construction mitigation within wetlands described in Section III.C.2.a.i.(A) above, the proposed facilities along the primary route will not impact the habitat of any species of special concern that exists in close proximity to the proposed route. Based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land resources.

iii. Land Use

The Company asserted that the construction and operation of the proposed facilities along the primary route would have no impact on existing land uses adjacent to the route (Exh. NEP-7, at 3-25). NEPCo explained that the primary route is located within four Town

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88 NEPCo stated that the Massachusetts Natural Heritage and Endangered Species Program office has requested that these two wildlife species not be publicly identified (Exh. NEP-7, at 3-29).

of Uxbridge zoning districts as follows: (1) an industrial zone extending from the Uxbridge substation to the Providence and Worcester railroad tracks with adjacent uses including the substation, a mill complex, other businesses and undeveloped land; (2) a business zone extending from the railroad to just west of Route 122 with businesses and residences located along the Route 122 crossing; (3) a residential zone extending from just west of Route 122 to the west of Richardson Street, with adjacent residences, including a new 40-unit townhouse development, farmland and undeveloped woodland; and (4) an agricultural zone extending from west of Richardson Street to the existing Millbury-Woonsocket ROW with the adjacent worked and cleared farmland areas (id.). NEPCo indicated that public utility uses are not specifically permitted uses in any of these districts and, therefore, has petitioned the Department for an exemption from the Town of Uxbridge Zoning Bylaw (Exh. HO-E-2b; DPU 94-182).

NEPCo stated that the Uxbridge spur ROW has been continuously maintained as a transmission line ROW since 1914 (Exh. NEP-7, at 3-26). The Company indicated that there are 10 residences within 100 feet of the ROW along the primary route (Exh. HO-E-13A). The Company noted that it has no specific agreements with abutters to allow alternative uses of the primary route but that alternative uses of the primary route include walking and all-terrain vehicle paths and driveways (Exh. HO-E-22). The Company indicated that it has no record of complaints related to electrical noise from the existing facilities, communications interference from the existing facilities or off-road vehicle use or other unauthorized access along any portion of the existing ROW along the proposed route (Exh. HO-E-8).

The Company stated that during construction, noise mufflers would be used on construction equipment to reduce construction noise at nearby residences (Exh. NEP-7, at 3-25). The Company also indicated that there are no schools, day care centers, hospitals, nursing homes or other sensitive receptors within 100 feet of the edge of the ROW (Exh. HO-E-23).

With respect to historical resources, the Company noted that four National and State Historic Register sites are located near the primary route (Exh. NEP-7, at 3-28). However, the Company stated the proposed facilities would not impact these historic properties because the visual effect of the proposed facilities would not be noticeably different than that of the existing transmission line facilities (id.).[89]

With respect to the Uxbridge substation, the Company indicated that new transformers likely would be relocated to the northern section of the substation which is outside the floodplain (Exh. HO-A-14; Tr. 2, at 49). The Company stated that such relocation would require an expansion of the substation fence within Company-owned land (Tr. 2, at 49).[90] The Company indicated that the residence located nearest to the Uxbridge substation is located approximately 625 feet to the west of the nearest substation fence (Exh. HO-E-10; Tr. 2, at 43-45). The Company indicated that transformers are the source of noise within a substation and that low-noise transformers would be installed as part of the proposed project (Exh. HO-E-11). NEPCo added that it is not aware of any complaints about the existing noise levels at the Uxbridge substation (id.).[91]

The record demonstrates that land use along the primary route is varied with a small number of residences but no sensitive receptors in close proximity to the existing ROW. The proposed route has been maintained continuously for an extended period of time. Construction of the proposed facilities along the primary route would not interfere with existing land uses along the route. Further, any expansion of the Uxbridge substation would take place within Company-owned land. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land use.

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89 The Company provided a letter from the Massachusetts Historical Commission which indicated that the proposed facilities would not have an adverse effect on historic resources (Exh. HO-RR-12).

90 The Company indicated that local permission, but not necessarily a zoning exemption, likely would be required for the substation work (Tr. 2, at 50).

91 The Company indicated that it has not prepared a noise analysis of current and anticipated conditions at the Uxbridge substation (Exh. HO-E-11).

iv. Visual Impacts

The Company asserted that construction of the proposed facilities along the primary route would not result in significantly increased visibility of towers and conductors (Exh. NEP-7, at 3-27). The Company indicated that the existing 69 kV transmission lines within the Uxbridge spur ROW are constructed on 14 lattice steel towers which are approximately 75.5 feet in height (id. at 1-1, 3-16). In order to construct the proposed 115 kV transmission lines, the Company indicated that: (1) the height of three of the existing towers will be increased by approximately 13 feet; (2) the height of eight of the existing towers will be increased by approximately five feet; and (3) three of the existing towers will be replaced by seven poles ranging in height from 65 feet to 90 feet (id. at 3-16; Exh. HO-E-25b).[92] The Company added that, because no new vegetative clearing will be required to construct the proposed facilities, there will be no significant change in the existing vegetative screening of the Uxbridge spur ROW (Exh. NEP-7, at 3-28).

The record demonstrates that the incremental visual impacts of the proposed facilities would be minimal. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to visual impacts.

v. Magnetic Field Levels

The Company calculated the highest magnetic field levels for the existing and proposed transmission lines along the Uxbridge spur ROW, based on estimated 1995 summer normal peak loads, at four locations including: (1) the left (north) ROW edge; (2) the right (south) ROW edge; (3) within the ROW; and (4) at the residence closest to the ROW (Exhs. HO-RR-10; HO-E-15a; NEP-10, exh. FRB-7). The Company's calculations indicated that magnetic field levels would decrease from current levels at the closest residence and at the

92 NEPCo stated that the towers would exceed the height restrictions set forth in Section IX of the Town of Uxbridge Zoning Bylaw (Exh. HO-E-2b). The Company has petitioned the Department for an exemption from Section IX (Exh. HO-E-2b; DPU 94-182).

left ROW edge, and would increase at the right ROW edge and within the ROW (Exhs. HO-RR-10; HO-E-15a; NEP-10, exh. FRB-7). See Table 1.

The Company stated that magnetic field levels increase with an increase in current and decrease as the distance from a transmission line increases (Exhs. HO-E-14b; HO-E-17). In addition, the Company stated that design features of a transmission line can lower magnetic field levels (Tr. 1, at 22-23). Mr. Barys explained that magnetic fields are lower if the three conductors that make up each circuit are arranged in certain configurations (id.).

With respect to the proposed project, the Company stated that magnetic field levels would be related to: (1) the magnitude of the current carried on the four transmission lines within the Uxbridge ROW, i.e., the two existing 13.8 kV lines and the two proposed 115 kV lines; (2) the distance from these lines; and (3) the conductor configuration of the four lines (id. at 21; Exh. HO-E-14b). The Company indicated that, in designing the proposed installation of the 115 kV lines on the ROW, it determined the optimum configuration of conductors on each circuit of both the existing 13.8 kV lines and the proposed lines to provide the lowest magnetic fields at the edge of the ROW, thus compensating for some of the increase in magnetic field due to increased current flow (Exh. HO-E-14b; Tr. 1, at 22-23, 97). However, the Company noted that as a consequence of optimizing conductor configuration, the magnetic field profile would be rearranged such that the magnetic field strength on portions of the ROW would be increased (Exh. HO-E-14b).

In addition, the Company calculated magnetic field levels for 1995 summer normal peak loads for the residence closest to the Uxbridge substation and the residence closest to the intersection of the Uxbridge spur ROW and Millbury-Woonsocket ROW (1) with the existing facilities, and (2) with the proposed facilities (Exhs. HO-E-12; HO-E-16b). The Company indicated that magnetic field levels would decrease at both locations with the operation of the proposed facilities (Exhs. HO-E-12; HO-E-16b). See Table 1.

The record demonstrates that with the operation of the proposed facilities, magnetic field levels would decrease at the closest residence to the ROW and at the left ROW edge, would increase at the right edge of the ROW, and would increase substantially within the ROW. The Company has incorporated features into the design of the proposed facilities that would decrease magnetic field levels at the edge of the ROW. The Siting Board also suggested that the Company implement feasible and cost-effective measures to discourage access to the ROW in general. See Section II.B.5.c, above. Accordingly, based on the foregoing, the Siting Board finds that, with the use of the above noted mitigation measures, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to magnetic field levels.

vi. Conclusions on Environmental Impacts

In Section III.C.2.a. above, the Siting Board has reviewed the information provided by the Company regarding environmental impacts of the proposed facilities along the primary route and the potential mitigation measures. The Siting Board finds that the Company has provided sufficient information regarding environmental impacts of the proposed facilities along the primary route and potential mitigation measures for the Siting Board to determine whether environmental impacts would be minimized and whether the appropriate balance among environmental impacts and among environmental impacts, cost, and reliability would be achieved.

In Section III.C.2.a, above, the Siting Board has found that: (1) with the utilization of the above noted mitigation measures, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to water resources; (2) the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land resources; (3) the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land use; (4) the environmental impacts of the proposed facilities along the primary route would be minimized with respect to visual impacts; and (5) with the use of the above noted mitigation measures, the proposed facilities along the primary route would be minimized with respect to magnetic field levels.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized. In Section III.C.2.c, below, the Siting Board addresses whether an appropriate balance among environmental impacts and among environmental impacts, cost, and reliability would be achieved.

b. Cost

The Company asserted that the construction of the proposed transmission line along the primary route is the least-cost alternative based on construction cost, operation and maintenance ("O&M") costs, and line loss costs (Exhs. HO-C-1; HO-C-2; NEP-7, at 3-12). With respect to construction costs, NEPCo estimated that the proposed transmission line along the primary route would cost $1,970,000 based on construction, materials, engineering, permitting, contingency, ROW and substation costs (Exh. HO-C-1). NEPCo stated that annual O&M costs would be $3,100 for the primary route (Exh. HO-C-2). The Company stated that this estimate was based on the average O&M cost per mile for all the Company's overhead lines (id.).[93] In addition, the Company stated that the primary route would have the lowest cost for line losses because it is the shortest route (Exh. NEP-7, at 3-2).

The Siting Board finds that the Company has provided sufficient cost information for the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts, cost, and reliability.

c. Conclusions

The Siting Board has found that the Company has provided sufficient information regarding environmental impacts of the proposed facilities along the primary route and potential mitigation measures for the Siting Board to determine whether environmental impacts would be minimized and whether the appropriate balance among environmental impacts and among environmental impacts, cost, and reliability would be achieved. In addition, the Siting Board has found that the environmental impacts of the proposed facilities along the primary route would be minimized. The Siting Board also has found that the Company has provided sufficient cost information for the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

93 Mr. Browne stated that the range of accuracy of the overall cost estimates was plus or minus ten percent for the primary route (Tr. 2, at 63).

In Section III.C.2.a, above, the Siting Board reviewed the environmental impacts of the proposed facilities and proposed mitigation along the primary route with respect to water resources, land resources, land use, visual impacts, and magnetic field levels. For each category of environmental impacts, the Company demonstrated that, with the mitigation discussed above, the impacts would be minimized.

Accordingly, based on the foregoing, the Siting Board finds that the proposed facilities along the primary route would achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost, and reliability.

3. Analysis of the Proposed Facilities along the Alternative Routes and Comparison

a. Environmental Impacts of the Proposed Facilities along the Alternative Routes and Comparison

In this Section, the Siting Board evaluates the environmental impacts of the proposed facilities along the alternative routes and potential mitigation for such impacts, including the proposed mitigation and, as necessary, any identified options for additional mitigation. As part of its evaluation, the Siting Board addresses whether the petitioner has provided sufficient information for the Siting Board to determine (1) whether environmental impacts would be minimized, and (2) whether the appropriate balance among environmental impacts and among environmental impacts, cost and reliability would be achieved along each route. The Siting Board also addresses whether the environmental impacts of the proposed facilities along the alternative routes would be minimized. Finally, the Siting Board compares the environmental impacts of the primary route to the environmental impacts of each of the alternative routes.

i. Water Resources

(A) Alternative Route B

NEPCo stated that construction of the proposed facilities along Alternative Route B would impact wetland areas and an associated stream, but would not impact groundwater or wells (Exhs. HO-E-21; NEP-7, at 3-23, 3-24). The Company stated that Wetland #4, which extends along the primary route, also extends along Alternative Route B at the edge of the rail bed (Exh. HO-E-21). The Company stated that up to 17 poles would be placed in this wetland area, affecting up to 1700 square feet of wetlands, but that all work along this segment would be conducted from the rail bed so that no new access roads would be required (id.). The Company stated that Alternative Route B also would cross a forested "bordering vegetated wetlands" and an associated tributary of the Blackstone River[94] and that ROW clearing would convert the forest vegetation on both sides of the stream to open shrub (id.; Exh. NEP-7, at 3-21). The Company stated that the ROW clearing would have a long-term impact on the stream because, without the forest vegetation, the stream would be exposed to more sunlight, and its temperature potentially would increase (id. at 3-23). The Company also stated that, although structures would not be placed within this wetland, an access road might be constructed on either side of the stream, if needed (id. at 3-21, 3-22; Exh. HO-E-21). The Company stated that mitigation measures such as hay bales and siltation fences would be used to protect the stream and adjacent wetlands from construction sediment (Exh. NEP-7, at 3-23).

With respect to groundwater and wells, the Company stated that, although Alternative Route B crosses 0.5 miles of the Blackstone River aquifer related to Wetland #4, and could come within 1,000 feet of town well fields, construction of the proposed facilities along Alternative Route B would not impact groundwater or wells (id. at 3-8, 3-24; Exh. E-20, att.).

The record demonstrates that construction of the proposed facilities along Alternative Route B would impact wetland areas and one stream. A significant number of poles -- several times the number under the primary route -- would be installed within Wetland #4 and the related aquifer area. Forest vegetation would be cleared in another wetland, resulting in a change in vegetative cover and a potential temperature change to a stream. The Company has described certain construction methods that would be used to minimize construction-related impacts to those areas. However, if the Company were to pursue this

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94 The Company noted that the stream is also crossed by the primary route but is wider at the crossing point of Alternative Route B (Exh. NEP-7, at 3-23).

route, the Siting Board would expect the Company to explore ways to reduce the overall extent of construction within wetlands. For instance, the Siting Board would expect the Company to consider constructing the transmission line on double-circuit pole structures rather than single-circuit pole structures in order to reduce both the number of structures that would be installed within sensitive areas, and the width of the ROW. Thus, the Siting Board finds that the Company has not demonstrated that the environmental impacts of Alternative Route B would be minimized with respect to water resources.

(B) Alternative Route G

The Company stated that Route G also would cross Wetland #4 and a stream, and potentially would cross a second wetland area along High Street (Exh. NEP-7, at 3-23, 3-24). However, the Company stated that impacts to these resources would be construction-related, and that the extent of impacts would depend on the specific underground location of the transmission line (id.). The Company stated that construction impacts to Wetland #4 would result from trench excavation, transmission line installation and regrading, and would be temporary and confined to work areas (id.). The Company stated that to mitigate such construction impacts, it would: (1) use swamp mats for equipment; (2) segregate, stockpile and restore excavated soils; (3) crown the restored trench to allow for soil settlement to original grade; and (4) use erosion and sediment control devices along the entire trench length (id.). In addition, the Company stated that a bordering vegetative wetland surrounds a small pond located on the southern side of High Street but that construction would not impact that wetland if construction was confined to the existing road pavement (id.).

The Company stated that Alternative Route G also crosses a small stream that passes through a 16-inch concrete culvert beneath the roadway along the route (id. at 3-23). The Company indicated that impacts of the 115 kV transmission line crossing the stream would be dependent on the crossing location and construction methods used, but that impacts such as sedimentation could be minimized by boring, or, depending on alignment, the use of temporary flumes, and by limiting duration of construction activities within the stream (id. at 3-24).

Finally, with respect to groundwater, the Company stated that Alternative Route G crosses 0.15 mile of the Blackstone River aquifer, which is within Wetland #4, but that construction of the proposed facilities along this route would not impact groundwater resources (id. at 3-8, 3-22; Exh. HO-E-20, att.).

The record demonstrates that construction of the proposed facilities along Alternative Route G would cross Wetland #4 and the related aquifer area, an underground culverted creek and possibly one additional wetland area, depending on the exact placement of the underground transmission line within the roadway. The record also indicates that potential impacts would be construction-related and thus short-term. The Company has described certain construction methods that would be used to minimize construction-related impacts to these areas. If the Company were to pursue this underground route, the Siting Board would expect the Company to consider minor route variations and adjustments to the alignment, depth and width of the transmission line trench to minimize impacts and maintain existing groundwater flows to the greatest extent possible. In addition, due to the location of Wetland #4 and the related aquifer close to the Uxbridge substation, the Siting Board would expect the Company to consider overhead construction across this area to the substation. Thus, the Siting Board finds that the Company has not demonstrated that the environmental impacts of Alternative Route G would be minimized with respect to water resources.

ii. Land Resources

(A) Alternative Route B

The Company stated that an 80-foot to 120-foot wide ROW would be required for the construction of the proposed facilities along Alternative Route B to allow for adequate clearances for line operation and maintenance (Exhs. NEP-7, at 3-18; HO-S-5).[95] The Company indicated that construction of the proposed facilities along Alternative Route B would require some side clearing along the upland forested edges of the railroad ROW (Exh. NEP-7, at 3-26). In addition, approximately 13 acres of oak forest and mixed forest

95 The Company stated that 120 feet is its normal ROW width for two 115 kV lines constructed using single-pole davit arm structures (Exh. HO-S-5).

along the new ROW as it crosses private land would be cleared and maintained with low-growing vegetation (id.). The Company added that there are no rare or endangered plant species or natural communities in the vicinity of Alternative Route B (id. at 3-29). The Company further stated that the same species of special concern that exist in the vicinity of the primary route exist in the vicinity of Alternative Route B, but that construction of the proposed facilities along Alternative Route B should not impact either species (id.). The Company also indicated that much of Alternative Route B would be constructed along slopes and would cross areas which are susceptible to soil erosion, but that erosion protection measures could be used to prevent erosion and sedimentation (id. at 3-27).

The record demonstrates that, compared to the primary route, construction of the proposed facilities along Alternative Route B would require a significant amount of forest clearing. Were the Company to pursue this route, the Siting Board would expect the Company to consider possible means to reduce the width of the ROW and thereby reduce tree clearing. Thus, in comparing the primary route to Alternative Route B, the Siting Board finds that the Company has not demonstrated that the environmental impacts of Alternative Route B would be minimized with respect to land resources.

(B) Alternative Route G

The Company indicated that construction of the proposed facilities along Alternative Route G would require a minimum of selective tree removal and that, depending on the exact location of the underground line, up to 18 trees might be affected by construction (id. at 3-26, 3-27). In addition, the Company indicated that Alternative Route G would not be susceptible to soil erosion (id. at 3-27).

The record demonstrates that construction of the proposed facilities along Alternative Route G would require a minimal amount of tree removal and that tree removal might be further minimized by refining the alignment of the underground line. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of Alternative Route G would be minimized with respect to land resources.

iii. Land Use

(A) Alternative Route B

The Company indicated that Alternative Route B is located within industrial, business and residential zoning districts in the Town of Uxbridge and also passes through the Floodplain District and Groundwater Protection District (Exh. HO-E-2c).[96] NEPCo stated that there are 14 residences within 100 feet of the ROW for that route, one located at the ROW edge and the remaining 13 located from 65 feet to 100 feet from the ROW edge (Exh. HO-E-13b). There are also two sensitive receptors, i.e., two in-home day care centers within 100 feet of the edge of the ROW, one at the edge of the ROW and one approximately 100 feet from the edge of the ROW (Exh. HO-E-23). In addition, the Company noted that there are several historic sites, including one National and State Historic Register site, to the north and west of Alternative Route B (Exh. NEP-7, at 3-28). The Company noted that the proposed facilities along Alternative Route B might be visible from such historic sites at the Route 122 and Quaker Highway crossings and along the railroad ROW (id.).

The record demonstrates that land use along Alternative Route B is comparable to the land use along the primary route. However, there are two in-home day care centers within 100 feet of the ROW, one of which is right at the edge of the ROW. Were the Company to pursue this route, the Siting Board would expect the Company to evaluate potential impacts to sensitive receptors such as day care centers, and make minor route adjustments, if appropriate. Thus, the Siting Board finds that the Company has not demonstrated that the environmental impacts of Alternative Route B would be minimized with respect to land use.

(B) Alternative Route G

The Company stated that Alternative Route G is located within: (1) an industrial zone which is undeveloped; (2) a business zone which includes a mix of commercial businesses and single and two-family residences; (3) a residential zone which includes a medium density single-family neighborhood, a development of two family homes and single family homes on

[96] NEPCo indicated that construction of the proposed facilities along Alternative Route B would require comparable zoning exemptions to those required for the primary route (Exh. HO-E-2c).

larger lots; and (4) an agricultural zone (id. at 3-26; Exh. HO-E-2c). In addition, the Company stated that Alternative Route G traverses the Floodplain District and Groundwater Protection District (Exh. HO-E-2c).[97] The Company indicated that there are 87 residences within 100 feet of the ROW but no sensitive receptors such as schools, nursing homes or day care facilities (Exhs. HO-E-13g; NEP-7, at 3-26).

The Company indicated that Alternative Route G would pass near two historic buildings that are National and State Historic Register sites (Exh. NEP-7, at 3-28). However, the Company noted that, as the route would be constructed underground, Alternative Route G would have no significant impact on these sites, except during a relatively short construction period (id.).

The record demonstrates that Alternative Route G would traverse comparable zoning districts as the primary route but would be located within 100 feet of a significant number of residences. However, underground construction of the route will not conflict with any existing land uses except during a relatively short construction period. Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along Alternative Route G would be minimized with respect to land use.

iv. Visual Impacts

(A) Alternative Route B

The Company indicated that Alternative Route B would be constructed on (1) two lines of single circuit steel poles approximately 95 feet in height along the existing railroad corridor, and (2) two lines of single circuit wood poles, approximately 75 feet in height along the new ROW across private land (id. at 3-18). NEPCO stated that forest vegetation adjacent to the ROW would screen much of the proposed facilities along Alternative Route B

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97 NEPCo indicated that if the proposed facilities were constructed along Alternative Route G, it would require comparable zoning exemptions to those required for the primary route (Exh. HO-E-2c). In addition, the Company stated that construction along Alternative Route G potentially would require an exemption from the Town of Uxbridge Zoning Bylaw that prohibits "[u]nderground storage of all petroleum products and toxic or hazardous materials without a permit" due to the dielectric fluid within the cable insulation (Exh. HO-E-2c).

except at road crossings (id.). NEPCo further stated that where possible, vegetation buffers would be left at road crossings but that the transmission line would be visible to several residences and businesses along the roads adjacent to and near the ROW (id.).

The record demonstrates that the proposed facilities along Alternative Route B would be visible from a number of residences and businesses and at road crossings. However, a large part of the route would be screened by forest vegetation and, where possible, vegetative buffers would be left in place at road crossings. Accordingly, based on the foregoing, the Siting Board finds that the impacts of the proposed facilities along Alternative Route B would be minimized with respect to visual impacts.

(B) Alternative Route G

The Company indicated that there would be no visual impacts associated with the proposed facilities along Alternative Route G as the entire route would be placed underground (id.).

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along Alternative Route G would be minimized with respect to visual impacts.

v. Magnetic Field Levels

The Company calculated the highest magnetic field levels for the proposed facilities along Alternative Route B and Alternative Route G based on estimated 1995 summer normal peak loads (Exh. HO-RR-10).

(A) Alternative Route B

With respect to Alternative Route B, the Company indicated that it would use a circuit phase configuration that would minimize magnetic field levels (Exh. HO-E-17). The Company calculated magnetic field levels at four locations including: (1) the left ROW edge; (2) the right ROW edge; (3) within the ROW; and (4) at the residence closest to the ROW (Exhs. HO-E-17; HO-RR-10). See Table 1. In comparing the magnetic field levels of the proposed facilities along the primary route and Alternative Route B, the Company's calculations indicate that the magnetic field levels would be slightly less for Alternative Route B at the residence closest to the ROW but would be greater for Alternative Route B at the other locations (Exh. HO-RR-10). See Table 1. The Company explained that magnetic field levels would be greater along Alternative Route B because the 115 kV transmission lines would be closer to the edge of the ROW (Exh. HO-E-17). The Company further explained that, with optimal phase configuration, a reduction in the distance between two circuits can reduce magnetic field levels and that the distance between the two 115 kV circuits is greater for Alternative Route B (id.).

The record demonstrates that magnetic field levels would be higher along Alternative Route B than along the primary route at both edges of the ROW and within the ROW. Were the Company to pursue this route, the Siting Board would expect the Company to consider possible means to reduce the magnetic field levels such as installation of the transmission line on double-circuit poles which would reduce the distance between the circuits. Thus, the Siting Board finds that the Company has not demonstrated that the environmental impacts of Alternative Route B would be minimized with respect to magnetic field levels.

(B) Alternative Route G

With respect to Alternative Route G, the Company estimated magnetic field levels on the ROW and at the closest residence (Exh. HO-RR-10).[98] The Company's calculations provide that the magnetic field levels at these two locations would be lowest along Alternative Route G (id.; Exhs. HO-E-15a; NEP-10, exh. FRB-8). See Table 1.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facilities along Alternative Route G would be minimized with respect to magnetic field levels.

98 The Company indicated that for Alternative Route G, the maximum ROW magnetic field level was calculated at one meter above the street and the closest residence was estimated to be approximately seven feet from the center trench line (Exh. HO-RR-10).

vi. Conclusions on Environmental Impacts

In Section III.C.3.a above, the Siting Board reviewed the information provided by the Company regarding the environmental impacts of the proposed facilities along the alternative routes and potential mitigation measures with respect to water resources, land resources, land use, visual impacts and magnetic field levels. For all categories, the Company provided sufficient information regarding the environmental impacts of the proposed facilities along the alternative routes for the Siting Board to compare the environmental impacts of the proposed facilities along the primary route to those of the proposed facilities along the alternative routes. In addition, the Company provided information regarding certain mitigation measures along the alternative routes. However, as noted above, for many of the environmental categories, the Siting Board determined that it would expect the Company to consider additional mitigation if the Company were to pursue one of the alternative routes.

In Sections III.C.3.a.i to v, above, the Siting Board has found that the Company has not demonstrated that the impacts of the proposed facilities along Alternative Route B would be minimized with respect to water resources, land resources, land use and magnetic field levels and has demonstrated that impacts of the proposed facilities would be minimized with respect to visual impacts. Accordingly, on balance, the Siting Board finds that the Company has not demonstrated that the environmental impacts of the proposed facilities along Alternative Route B would be minimized.

In Sections III.C.3.a.i to v, above, the Siting Board has found that the Company has not demonstrated that the impacts of the proposed facilities along Alternative Route G would be minimized with respect to water resources and has demonstrated that the impacts of the proposed facilities would be minimized with respect to land resources, land use, visual impacts and magnetic field levels. However, the impacts to water resources of the proposed facilities along Alternative Route G would be construction-related and short-term. Accordingly, on balance, the Siting Board finds that the Company has demonstrated that the environmental impacts of the proposed facilities along Alternative Route G would be minimized.

The Siting Board next compares the environmental impacts of the primary route to each of the alternative routes. With respect to the primary route, the Siting Board has found that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land resources, land use, and visual impacts and, with the utilization of the above noted mitigation measures, would be minimized with respect to water resources and magnetic field levels.

The record demonstrates that, due, primarily to the creation of a new utility ROW, the impacts to water and forest resources would be significantly greater along Alternative Route B and the visual impacts along Alternative Route B also would be greater. Construction along Alternative Route B would require the installation of a number of new structures within a wetland area, clearing of a forested wetland on both banks of a stream and potential construction of an access road through a wetland, while the primary route would require modification to two existing structures within a wetland area and no new access road construction. In addition, construction along Alternative Route B would require clearing of a substantial amount of upland forest, while the primary route would not require tree clearing. Although the Siting Board has found that visual impacts of both routes have been minimized, the impacts of new poles along a new ROW along Alternative Route B would be greater than the incremental impacts of increasing the height of existing structures along the primary route. Finally, the magnetic field levels at the edge of the ROW and within the ROW would be greater for Alternative Route B.

Accordingly, based on the foregoing, the Siting Board finds that the proposed facilities along the primary route would be preferable to the proposed facilities along Alternative Route B with respect to environmental impacts.

In comparing the primary route to Alternative Route G, the record demonstrates that the impacts along Alternative Route G would be greater with respect to wetlands, while the impacts along the primary route would be greater with respect to visual impacts and magnetic field levels. Both routes would traverse Wetland #4. Construction of a trench for underground transmission line installation through this area would have a greater potential effect on underground water flow and drainage patterns than the modification of two existing structures that would be required for the primary route. Although the Siting Board has found that the magnetic field level impacts and visual impacts would be minimized for both routes, the magnetic field levels would be significantly lower within the ROW and at the edge of the

ROW for Alternative Route G. In addition, the visual impacts of an underground route would be less than the incremental impacts of continuing the use of the overhead line and increasing the height of existing structures.

Accordingly, based on the foregoing, the Siting Board finds that, on balance, the proposed facilities along the primary route and Alternative Route G would be comparable with respect to environmental impacts.

b. Cost of the Proposed Facilities Along the Alternative Routes and Comparison

i. Description

As noted in Section III.C.2.b, above, the Company asserted that the construction of the proposed transmission line along the primary route is the least-cost alternative based on construction costs, O&M costs and line loss costs (Exhs. HO-C-1; HO-C-2; NEP-7, at 3-12). The Company provided a comparison of construction costs as follows:

Category	Primary Route	Alternative B	Alternative G
Construction labor and equipment	960,000	1,300,000	1,920,000
Materials	310,000	605,000	2,225,000
Engineering	205,000	250,000	350,000
Permitting	270,000	325,000	295,000
Contingency	225,000	280,000	850,000
ROW acquisition		400,000	25,000
Substation costs			1,180,000
TOTAL	1,970,000	3,160,000	6,575,000

(Exh. HO-C-1).

The Company indicated that construction costs were estimated based on total hours of construction labor and equipment time for recently completed, similar projects, and on established hourly rates (Exh. HO-C-1). The Company further indicated that prices for:

(1) new material were based on prices for similar material; (2) engineering and permitting were based on prices for recently completed projects; and (3) ROW acquisition were based on on-going real estate transactions (id.).[99] The Company added that contingency costs were estimated as a percentage of the other categories (id.).[100]

NEPCo stated that annual O&M costs would be: (1) $3,100 for the primary route; (2) $4,300 for Alternative B; and (3) $18,000 for Alternative G (Exh. HO-C-2). The Company stated that the O&M costs for the overhead routes were estimated based on the average O&M cost per mile for all the Company's overhead lines and that the higher cost for Alternative B reflects its greater length, compared to the primary route (id.). The Company added that the higher O&M costs for Alternative G reflect requirements for an annual corrosion survey, weekly checks of pressure, and cathodic protection system operation and failure resolution (id.).[101] In addition, as noted in Section III.C.2.b above, the Company stated that the primary route would have the lowest cost of line losses because it is the shortest route (Exh. NEP-7, at 3-12).

ii. Analysis

The record demonstrates that the Company has provided sufficient information regarding the construction costs and O&M costs of the proposed facilities along the Alternative Routes for the Siting Board to compare such costs with the cost of the proposed facilities along the primary route.

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99 The Company indicated that costs were adjusted to reflect expected changes in prices between the time of the estimate and time of construction (Exh. HO-C-1).

100 The Company stated that percentages for overhead transmission line contingency were estimated at: (1) 15 percent for construction; (2) ten percent for materials; and (3) two percent for engineering and permitting (Exh. HO-C-1). The Company further stated that percentages for underground transmission line contingency were estimated at: (1) 25 percent for construction; (2) 15 percent for materials; and (3) five percent for engineering and permitting (id.).

101 Mr. Browne stated that the range of accuracy of the overall cost estimates would be (1) ten percent for the primary route, and (2) 25 percent for each of the alternative routes (Tr. 2, at 63).

In comparing the cost of the primary route to Alternative Route B, the Company's analysis indicates that: (1) the construction cost of Alternative Route B would be 60 percent greater; (2) O&M costs would be 39 percent greater; and (3) line loss costs would be greater. Accordingly, based on the foregoing, the Siting Board finds that the proposed facilities along the primary route are preferable to the proposed facilities along Alternative Route B with respect to cost.

In comparing the cost of the primary route to Alternative Route G, the Company's analysis indicates that: (1) the construction cost of Alternative Route G would be 234 percent greater; (2) the O&M costs would be 481 percent greater; and (3) line loss costs would be greater. Accordingly, based on the foregoing, the Siting Board finds that the proposed facilities along the primary route are preferable to the proposed facilities along Alternative Route G with respect to cost. The Siting Board notes that, compared to Alternative Route G, the cost advantage of the primary route is significant with respect to both construction costs and O&M costs.

c. Conclusions

In comparing the primary route to Alternative Route B, the Siting Board has found that the proposed facilities along the primary route would be preferable to the proposed facilities along Alternative Route B with respect to (1) environmental impacts, and (2) costs.

In comparing the primary route to Alternative Route G, the Siting Board has found that (1) the proposed facilities along the primary route and Alternative Route G would be comparable with respect to environmental impacts, and (2) the proposed facilities along the primary route would be preferable to the proposed facilities along Alternative Route G with respect to cost. In addition, the record demonstrates that the cost advantage of the proposed facilities along the primary route would be significant with respect to both construction costs and O&M costs.

The Siting Board notes that its standard of review requires it to determine whether an appropriate balance would be achieved along each alternative route between conflicting environmental concerns as well as among environmental impacts, cost and reliability. This analysis is intended to facilitate an accurate comparison of the environmental impacts, costs and reliability of the primary and alternative routes, particularly where trade-offs between cost and environmental impacts could affect the outcome of the comparison. However, in this case, the Company has demonstrated the clear advantage of the primary route over each of the alternative routes. Alternative Route G is significantly more costly than the primary route and has comparable environmental impacts. Further environmental mitigation would decrease the environmental impacts only slightly, while potentially adding to the cost advantage of the primary route. Alternative Route B is both more costly and has significantly greater environmental impacts than the primary route. Although the environmental impacts of Alternative Route B could be reduced with additional mitigation, such additional mitigation would likely increase the cost of Alternative Route B, thus increasing the cost advantage of the primary route. Further, since the primary route follows an existing ROW and Alternative Route B requires a new ROW, additional environmental mitigation along Alternative Route B would not significantly affect the environmental advantage of the primary route.

In Section III.C.2.c, above, the Siting Board found that the proposed facilities along the primary route would achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Based on that finding and the clear advantage of the primary route over each of the alternative routes as discussed above, the Siting Board finds that a balancing of environmental impacts, cost and reliability for the alternative routes is unnecessary for the purposes of this review.

Although the level of analysis provided by the Company in balancing the environmental impacts and cost of the alternative routes was acceptable in this review given the clear advantage of the primary route relative to the alternative routes, such a level of analysis would not be acceptable in a review of a proposed transmission line or gas pipeline where the advantages of the respective routes are less clear.

Accordingly, based on the foregoing, the Siting Board finds that the proposed facilities along the primary route would be preferable to the proposed facilities along both Alternative Route B and Alternative Route G with respect to providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

IV. DECISION

The Siting Board has found that NEPCo has demonstrated that its existing supply system is inadequate to satisfy the existing load that is supplied by the Uxbridge substation, and, therefore, that additional energy resources are needed for reliability purposes in the Uxbridge area.

The Siting Board also has found that, on balance, the proposed project is preferable to the 69 kV upgrade and to the 115 kV double tap alternative.

The Siting Board further has found that NEPCo has considered a reasonable range of practical siting alternatives.

Finally, the Siting Board has found that the proposed facilities along the primary route would be preferable to the proposed facilities along Alternative Route B and the proposed facilities along Alternative Route G with respect to providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In addition, the Siting Board finds that the proposed project is consistent with the most recently approved long-range forecast of NEPCo's affiliated supply company MECo.

Accordingly, the Siting Board approves NEPCo's petition to convert the existing 69 kV supply to the Uxbridge #321 substation to 115 kV by looping an existing 115 kV line, located within NEPCo's Millbury-Woonsocket Right-of-Way, into the Uxbridge substation utilizing the Company's proposed route.

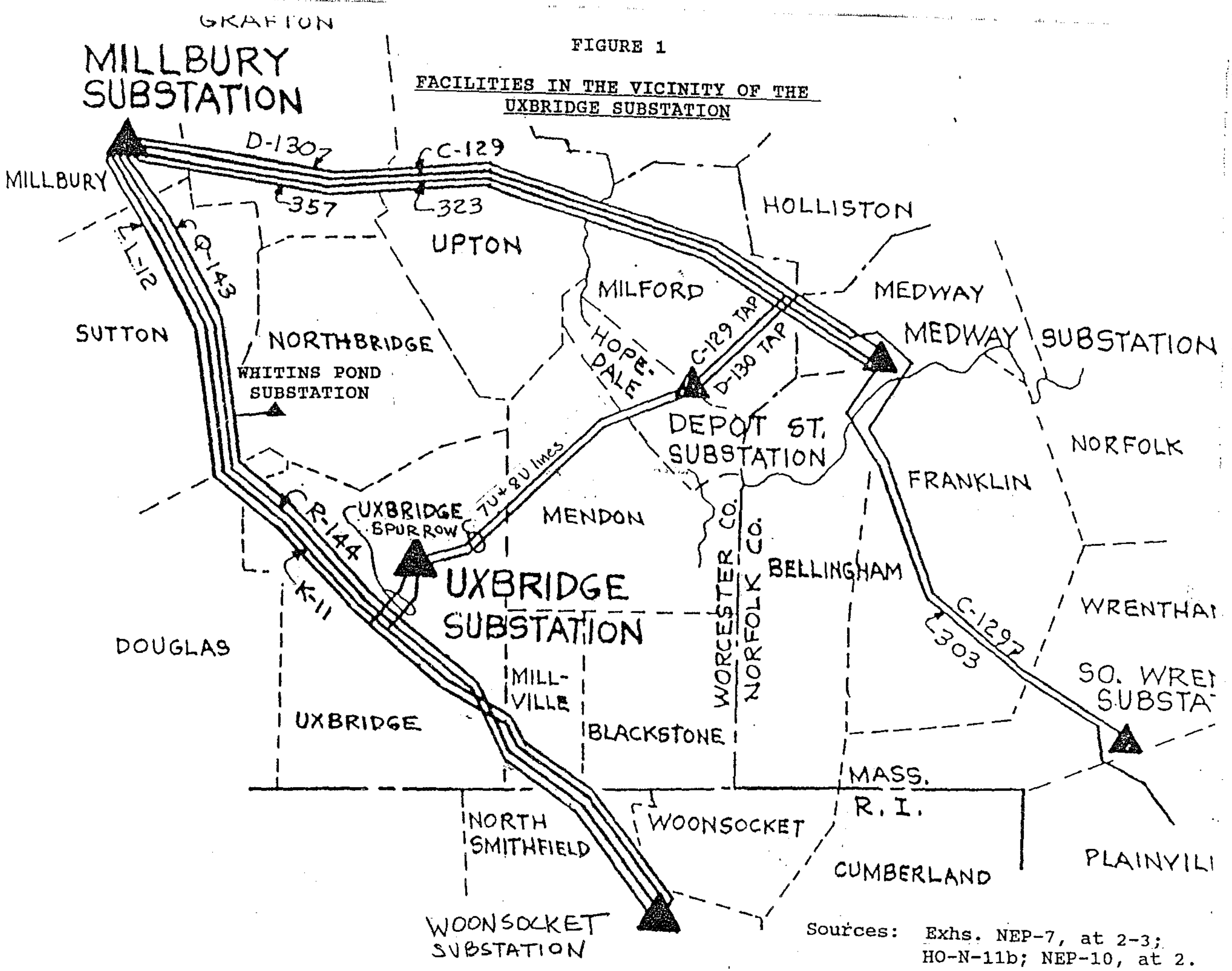
The Siting Board notes that the findings in this decision are based on the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the 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
Hearing Officer

Dated this 17th day of October, 1995

FIGURE 1

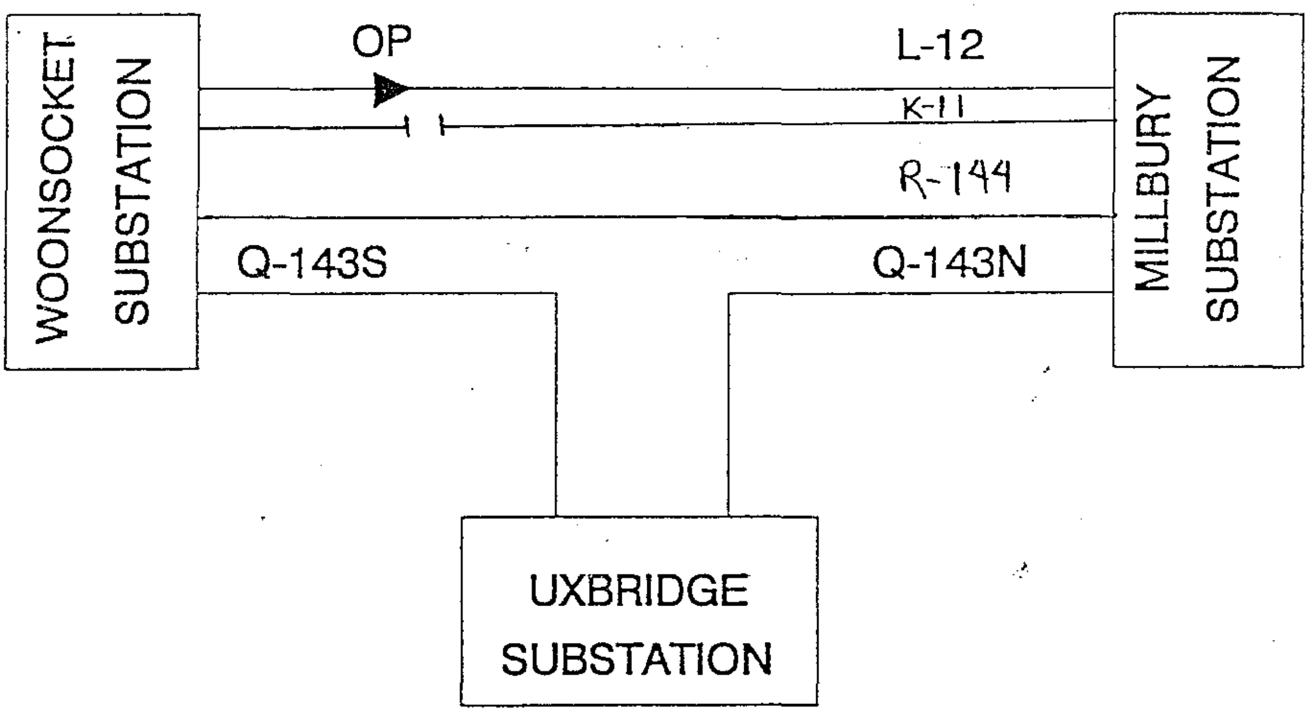
FACILITIES IN THE VICINITY OF THE UXBRIDGE SUBSTATION



Sources: Exhs. NEP-7, at 2-3; HO-N-11b; NEP-10, at 2.

FIGURE 2

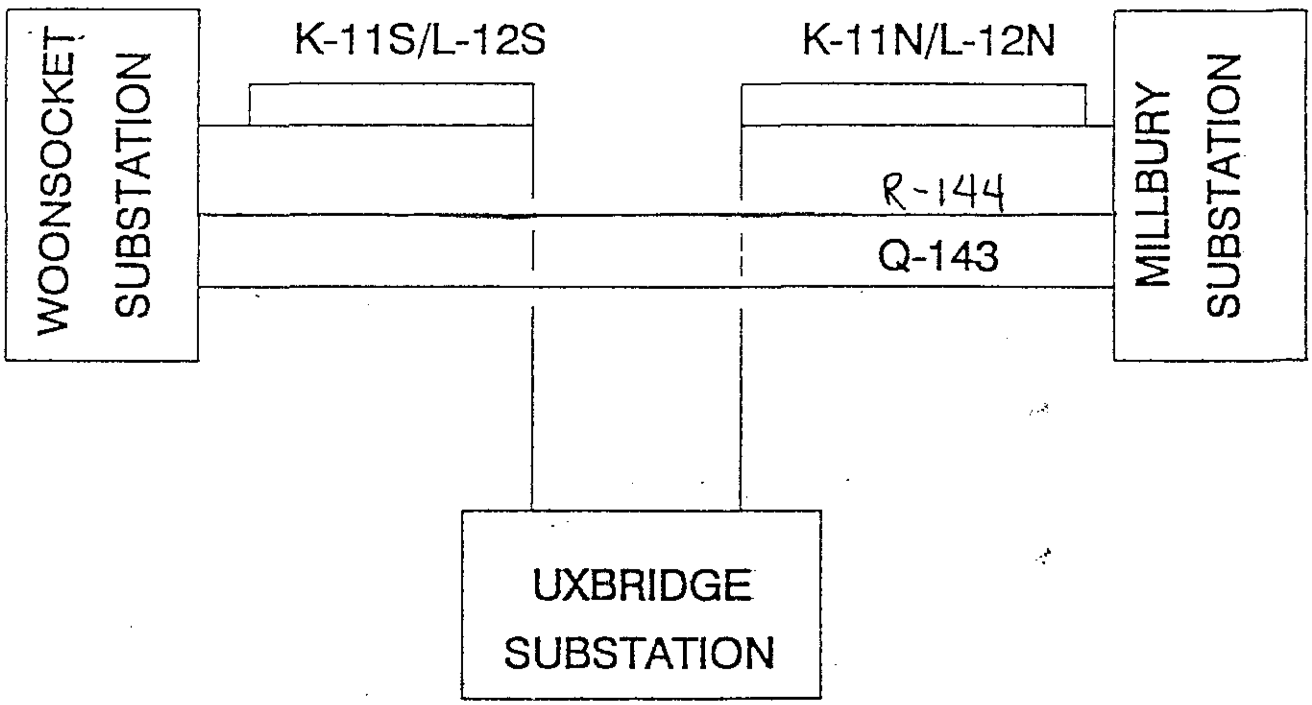
PROPOSED PROJECT
(Simplified One-Line Diagram)



Source: Exhs. NEP-7, at 2-4; 2-5.

FIGURE 3

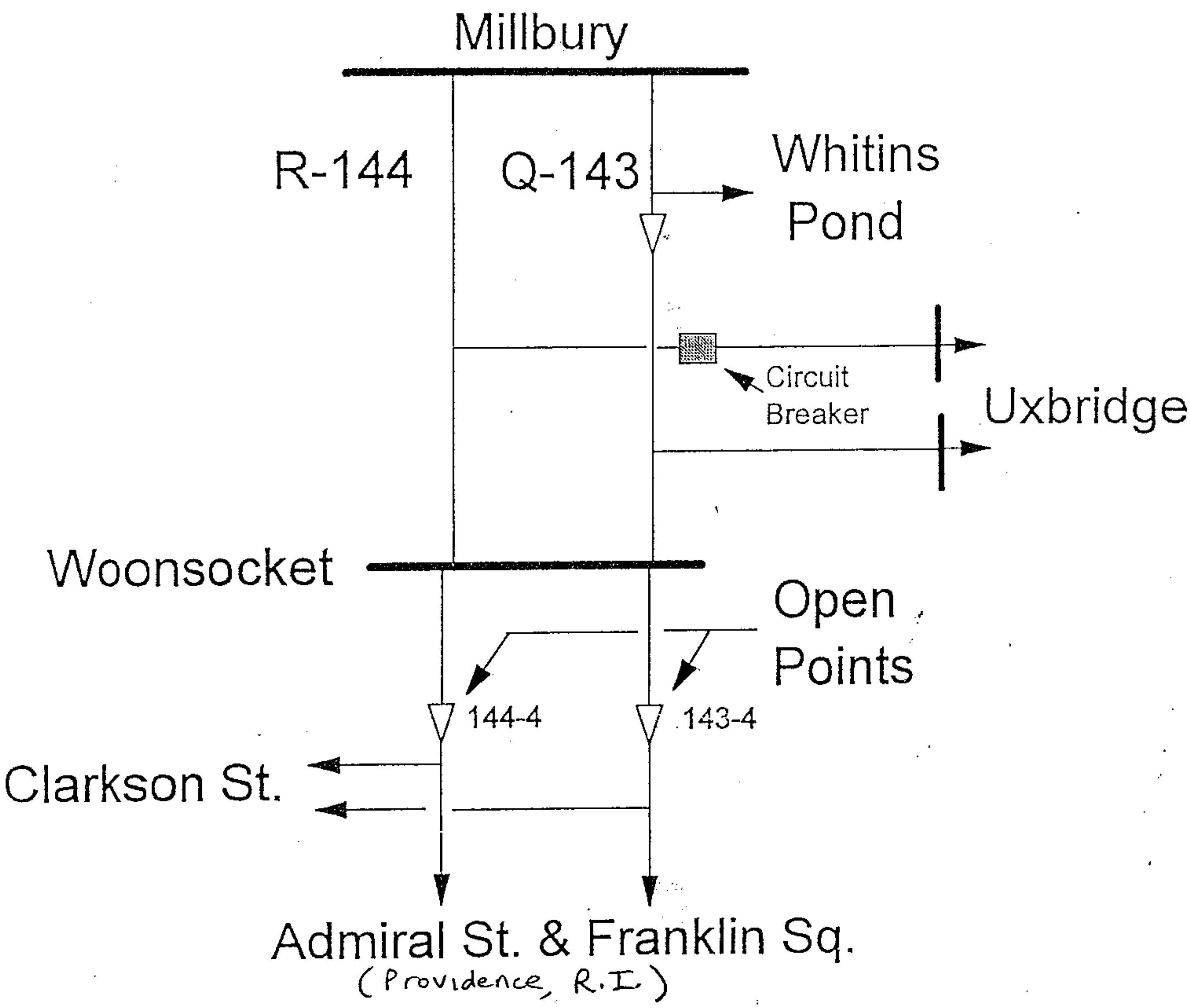
69 kV UPGRADE
(Simplified One-Line Diagram)



Source: Exh. NEP-7, at 2-4, 2-7.

FIGURE 4

115 kV DOUBLE TAP ALTERNATIVE
(Simplified One-Line Diagram)

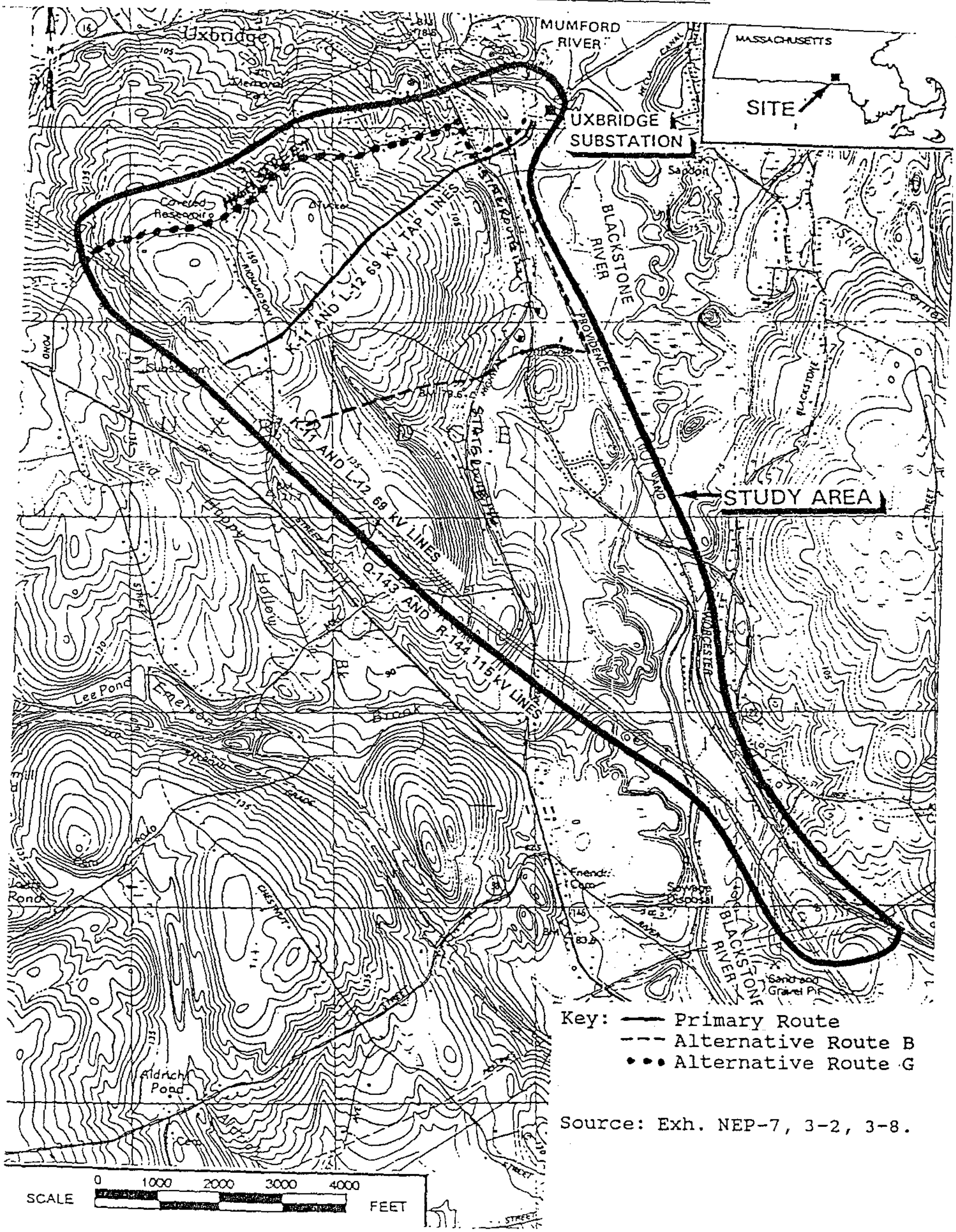


Note: This diagram shows the 115 kV double tap alternative with one circuit breaker on the R-144 line.

Source: Exh. HO-RR-15b.

FIGURE 5

PRIMARY AND ALTERNATIVE ROUTES



Key: ——— Primary Route
- - - Alternative Route B
• • • Alternative Route G

Source: Exh. NEP-7, 3-2, 3-8.

Table 1

Magnetic Field Calculations for Highest Levels at Various Locations on Uxbridge Spur ROW in mG

Project Alternatives	Left ROW Edge	Right ROW Edge	On ROW	Closest Residence to ROW
Existing	13.80	1.70	23.00	4.01
Proposed Project	12.40	3.40	92.90	3.50
69 kV Upgrade	7.00	1.00	19.60	2.80
115 kV Double Tap	7.40	0.40	7.70	3.00

Route Alternates	Left ROW Edge	Right ROW Edge	On ROW	Closest Residence to ROW	Closest Residence to Substation	Closest Residence to Intersection of ROWs
Existing	13.80	1.70	23.00	4.01	0.02	0.72
Primary Route	12.40	3.40	92.90	3.50	0.01	0.28
Alternate B	29.40	37.50	133.40	3.30		
Alternate G	NA	NA	1.90	1.00		

Sources: Exhs. HO-RR-10; HO-E-12; HO-E-15a; HO-E-16b; NEP-10, exh. FRB-8.

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of October 17, 1995 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Janet Gail Besser (Commissioner, DPU); Mary Clark Webster (Commissioner, DPU); David L. O'Connor (for Gloria C. Larson, Secretary of Economic Affairs); Sonia Hamel (for Trudy Coxe, Secretary of Environmental Affairs); and William Sargent (Public Member).

Sonia W. Hamel

Sonia Hamel
Acting Chairman

Dated this 17th day of October, 1995

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).

Energy Facilities Siting Board

100 Cambridge Street, Room 1200, Boston, Massachusetts 02202

(617) 727-1136

MEMORANDUM

To: All Parties and Interested Persons in EFSB 90-100R2;
Petition of Eastern Energy Corporation

From: Robert P. Rasmussen, Hearing Officer RPR

Date: March 29, 1996

Re: Action By Consent

Enclosed please find a copy of the Action By Consent which acts to terminate the above-referenced proceeding.

As this Action By Consent is a final decision of the Energy Facilities Siting Board ("Siting Board"), please be advised that G.L. c. 25, §5, as made applicable to actions of the Siting Board by G.L. c. 164, §69P, governs judicial review of this final decision.

Should you have any further questions, please do not hesitate to contact me or Diedre Shupp Matthews, the Director of the Siting Board.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Eastern Energy Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 90-100R2

ACTION BY CONSENT

This "Action by Consent" is made pursuant to authority granted the Chairman of the Energy Facilities Siting Board ("Siting Board") under 980 C.M.R. § 2.06. Section 2.06 provides the Siting Board with authority to render a decision "when it would be a hardship to the public welfare to defer the decision until the next scheduled meeting of the [Siting Board]." 980 C.M.R. § 2.06(1).

On June 27, 1995, the Siting Board by majority vote conditionally approved the petition of Eastern Energy Corporation ("EEC Petition") to construct a bulk generating facility and ancillary facilities in the City of New Bedford (Docket No. EFSB 90-100R2). Appeals of that Final Decision were taken by the Greater New Bedford NO-COALition and the Office of the Attorney General (Docket Nos. SJ-95-0399 and SJ-95-0405, respectively).

On February 6, 1996, Eastern Energy Corporation formally withdrew the EEC Petition, thereby mooting the Siting Board's June 27th Final Decision. As (1) the two appeals are pending and currently subject to Motions to Stay, filed by the Petitioners, which will expire on March 15, 1996, and (2) there are no meetings of the Siting Board scheduled or planned for scheduling in the near future, we find that it would be a hardship to the public welfare to defer a decision to rescind the June 27th conditional approval.

Now, therefore, the Siting Board by unanimous written consent do hereby rescind the conditional approval granted Eastern Energy Corporation in Docket No. EFSB 90-100R2 on June 27, 1995 to construct a bulk generating facility and ancillary facilities in the City of New Bedford.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe

John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

Mary Clark Webster
Commissioner
Department of Public Utilities

Janet Gail Besser
Commissioner
Department of Public Utilities

David L. O'Connor
for David A. Tibbetts
Secretary of Economic Affairs

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

William Sargent
Public Member

March 29, 1996
Effective Date

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John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

Mary Clark Webster
Mary Clark Webster
Commissioner
Department of Public Utilities

Janet Gail Besser
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William Sargent
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March 29, 1996
Effective Date

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John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

Mary Clark Webster
Commissioner
Department of Public Utilities

Janet Gail Besser

Janet Gail Besser
Commissioner
Department of Public Utilities

David L. O'Connor
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Secretary of Economic Affairs

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

William Sargent
Public Member

March 29, 1996
Effective Date

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

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Energy Facilities Siting Board/
Department of Public Utilities

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Janet Gail Besser
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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Berkshire Power Development, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 95-1

FINAL DECISION

Robert P. Rasmussen
Hearing Officer
June 19, 1996

On the Decision:

Phyllis Brawarsky
William Febiger
Enid Kumin
Barbara Shapiro

APPEARANCES: John A. DeTore, Esq.
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<u>Intervenor</u>

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<u>Intervenor</u>

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Interested Person

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Interested Person

TABLE OF CONTENTS

TABLES:

EXHIBITS:

LIST OF ABBREVIATIONS

Abbreviation	Explanation
ABB EV	ABB Energy Ventures, Inc.
ABB O&M	ABB Operations and Maintenance Department
ABB Power Generation	ABB Power Generation, Inc.
ACS	Advanced Cycle System
Actual peak, weather-normalized	The highest, reconstituted, weather-normalized 1994 summer peak load
AFBC	Atmospheric fluidized bed coal facility
AFBC alternative	The AFBC used in the Company's alternative technology analysis
Agawam	Town of Agawam
Agawam municipal system	Agawam municipal water supply system
Attorney General	Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995)
average peak	an average of the weather-normalized peak load summer peak candidate days
BACT	Best available control technology
Bay State	Bay State Gas Company
Berkshire-in case	A detailed economic analysis based on NEPOOL dispatch practices for the period 1999 through 2018, which included the dispatch of the proposed facility
Berkshire-out case	A detailed economic analysis based on NEPOOL dispatch practices for the period 1999 through 2018, which did not include the dispatch of the proposed facility
bmt	Billion metric tons
Bondi's Island	City of Springfield's Wastewater Treatment Facility at Bondi's Island
Box turtle	The eastern box turtle
BPD	Berkshire Power Development, Inc.
Btu/kwh	British thermal units per kilowatt hour
B&V	Black and Veatch Construction, Inc.
CAAA	Federal Clean Air Act Amendments of 1990

CCBA	Concerned Citizens & Businesses of Agawam
CCBA Brief	CCBA's initial brief
CELT	Capacity, Energy, Loads and Transmission (yearly reports prepared by NEPOOL)
Chez Josef	Chez Josef, Inc.
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)
CMF	C.M.F. Engineering, Inc.
CMP	Central Maine Power
CO	Carbon monoxide
CO_2	Carbon dioxide
Cobble Mountain	Cobble Mountain Reservoir in Blandford
Company	Berkshire Power Development, Inc.
Company Brief	BPD's initial brief
Company's Massachusetts base need scenario	A comparison of the 1994 Massachusetts normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast
Company Reply Brief	BPD's reply brief
Company's base need scenario	A comparison of the 1994 normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast
Connecticut River option	The alternative water supply option that would use water drawn from the Connecticut River in Agawam
Country Estates	Country Estates Nursing Home, Inc.
Country Estates Brief	Country Estates's reply brief
Court	Supreme Judicial Court
CRWC	Connecticut River Watershed Council, Inc.
CSC	Cogeneration Services Corporation
dBA	Decibel
DCR	Debt coverage ratios
DEIR	Draft Environmental Impact Report
Department	Department of Public Utilities

DFW	Division of Fisheries and Wildlife
DOMAC	Distrigas of Massachusetts
$/kWh	Dollars per kilowatt-hour
DSM	Demand side management
Eastern Edison	Eastern Edison Company
EMF	Electric and magnetic fields
EMI	Energy Management, Inc.
EPA	The United States Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPC turnkey contract	Turnkey construction contract
EPRI	Electric Power Research Institute
ERCs	Emission reduction credits
FERC	Federal Energy Regulatory Commission
FEV	The Fairfield Energy Venture
Firm gas supply	The assumption used in analyzing fuel costs that gas supply from the wellhead to the proposed facility will be firm
Fuel cell	Phosphoric acid fuel cell
GEP	Good Engineering Practice
Groundwater well option	The alternative water supply option that would use water drawn from wells
GT-24	The ABB GT-24 ACS Combined Turbine Generator
GTCC	Gas-fired combined cycle unit
GTCC alternative	A GTCC with oil backup used in the Company's alernative technology analysis
Higher heat rate	An assumed approximate heat rate of 7,000 Btu/kwh used in the Company's analysis of the costs and operating characteristics of the proposed facility
HQ II	Hydro-Quebec Phase II
HRSG	Heat recovery steam generator
IGCC	Integrated coal gasification combined cycle unit
IGCC alternative	The IGCC used in the Company's alternative technology analysis

Industrial Park	Shoemaker Industrial Park
IPP	Independent power producer
IRM	Integrated Resource Management
Iroquois	Iroquois Gas Pipeline Company
kV	Kilovolt
L_{90}	The level of noise that is exceeded 90 percent of the time
LAER	Lowest Achievable Emission Rate
The Lawlors	Cynthia A. and Frank J. Lawlor
lbs/MMBtu	Pounds per million British thermal units
L_{dn}	EPA's recommendation of a maximum day-night noise level of 55 dBA in residential areas
LOS	Levels of service -- a measure of the efficiency of traffic operations at a given location
lower heat rate	The actual predicted heat rate of the proposed facility used in the Company's analysis of the costs and operating characteristics of the proposed facility
MAAQS	Massachusetts ambient air quality standards
MCZM	Massachusetts Coastal Zone Management
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
mG	Milligauss
mgd	Million gallons per day
MMWEC	Massachusetts Municipal Wholesale Electric Company
MSW	Municipal solid waste facility
MW	Megawatt
NAAQS	National ambient air quality standards
NEC	Nantucket Electric Company
NEES	New England Electric System
NEPOOL	New England Power Pool
1993 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1993 CELT forecast, higher heat rate and firm gas supply

1993 CELT forecast	Regional load forecast derived from NEPOOL's 1993 CELT report reference forecasts of unadjusted summer and winter peak loads
1993 NEPOOL Massachusetts forecast	Massachusetts load forecast based on NEPOOL's Massachusetts-specific forecasts of summer and winter peak load for 1993 included in the 1993 NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts"
1993 TAG	1993 EPRI TAG Report
1994 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1994 final CELT forecast, higher heat rate and firm gas supply
1994 initial NEPOOL Massachusetts forecast	Massachusetts summer and winter peak demand forecast developed by prorating the 1994 final NEPOOL Massachusetts forecast by multiplying the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1994 initial CELT forecast to the 1994 final CELT forecast
1994 final NEPOOL Massachusetts forecast	Massachusetts load forecast based on NEPOOL's Massachusetts-specific forecasts of summer and winter peak load for 1994 included in the 1994 NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts"
1994 final CELT forecast	Regional load forecast derived from NEPOOL's final 1994 CELT report reference forecasts of unadjusted summer and winter peak loads
1994 GTF	The June 1994 Generation Task Force Assumption Book
1994 initial CELT forecast	Regional load forecast derived from NEPOOL's initial 1994 CELT report reference forecasts of unadjusted summer and winter peak loads
1994 Massachusetts normalized 2.5 percent forecast	Massachusetts load forecast derived by escalating the 1994 summer and winter Massachusetts-specific peaks, weather-normalized, by 2.5 percent per year
1994 normalized CELT forecast	Regional load forecast derived by escalating the 1994 summer highest weather-normalized peak by the growth rates embodied in the 1994 final CELT forecast
1994 normalized 2.5 percent forecast	Regional load forecast derived by escalating the 1994 summer and winter actual peaks, weather-normalized, by 2.5 percent per year

1995 CELT forecast	Regional load forecast derived from NEPOOL's 1995 CELT report reference forecasts of unadjusted summer and winter peak loads
1995 NEPOOL Massachusetts forecast	Massachusetts summer and winter peak demand forecast developed by prorating the 1994 final NEPOOL Massachusetts forecast by multiplying the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1995 CELT forecast to the 1994 final CELT forecast
NHESP	Natural Heritage and Endangered Species Program
NOx	Nitrogen oxides
NPV	Net present value
NRC	Nuclear Regulatory Commission
NSPS	New source performance standards
NSR	New source review
NU	Northeast Utilities
NUG	Non-utility generator
O_3	Ground-level ozone
O&M	Operation and maintenance
Order of Conditions	Agawam Conservation Commission's Order of Conditions
PASNY	Power Authority of the State of New York
Pb	Lead
PC	Pulverized coal facility
PC alternative	The PC used in the Company's alternative technology analysis
PDC	Power Development Company
Pendulum	Pendulum Gas Services
PFBC	Pressurized fluidized bed coal facility
PFBC alternative	The PFBC used in the Company's alternative technology analysis
PM-10	Particulates
Point of Pines	Point of Pines Beach Association v. Energy Facilities Siting Board, 419 Mass. 281 (1995)
PPA	Power purchase agreement

PSD	Prevention of significant deterioration
PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3
QF	Qualifying facility
RFP	Request for Proposals
ROW	Right-of-way
SACTI	Seasonal/Annual Cooling Tower Plume Impact model
SCBI	Springfield Corrugated Box, Inc.
SILs	Significant impact levels
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
SS-RFP	Site Selection RFP
Standard Uniform	Standard Uniform Services
SO_2	Sulfur dioxide
SOx	Sulfur oxides
TAG	EPRI Technical Assessment Guide
TEC	Taunton Energy Center
TELs	Threshold effects exposure limits
Tennessee	Tennessee Gas Pipeline Company
Town	Town of Agawam
tpy	Tons per year
Trout Unlimited	Trout Unlimited, Pioneer Valley Chapter #276
Updated 1994 CELT dispatch scenario	The Berkshire-out and Berkshire-in analyses based on the 1994 final CELT forecast, lower heat rate and firm gas supply
USGen	U.S. Generating Company
VOCs	Volatile organic compounds
WMECo	Western Massachusetts Electric Company
Wright	Wright, New York
Wright gas supply	The Company anticipated firm gas transportation contract from Wright, New York to the proposed project

XV

The Energy Facilities Siting Board ("Siting Board") hereby approves subject to conditions the petition of Berkshire Power Development, Inc. to construct a 252-megawatt, natural gas-fired generating facility and ancillary facilities in Agawam, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Berkshire Power Development, Inc. ("BPD" or "Company") has proposed to construct a nominal net 252-megawatt ("MW") natural gas-fired, combined-cycle independent power plant on an approximately 40-acre undeveloped parcel of land located at the Shoemaker Industrial Park in the Town of Agawam, Massachusetts ("Town" or "Agawam"), which would commence commercial operation in 1999 (Exh. BP-1A at 1-1, 2-1). The parcel is currently owned by Edward Zielinski and is used as a private runway for small aircraft with smaller portions used for vegetable production (id. at 2-3; Exh. HO-S-7(red.)(att.) at 2).

The proposed facility would be powered with natural gas delivered through a new, high-pressure pipeline interconnection with the nearby Tennessee Gas Pipeline ("Tennessee") facility, using low-sulfur (0.05 percent) distillate oil as a back-up fuel (Exh. BP-1A at 2-2, 2-5). The proposed facility would have an on-site fuel oil storage tank capable of holding enough oil to fuel the proposed facility for three consecutive days (id. at 4-22).

The electricity generated by the proposed facility would be transmitted via an approximately 500-foot long, 115 kilovolt ("kV") transmission line from the proposed facility to existing 115 kV Western Massachusetts Electric Company ("WMECo") transmission lines which cross the northern portion of BPD's Agawam site (id. at 2-5).

The major components of the proposed project include: (1) a GT-24 Advanced Cycle System ("ACS") Combustion Turbine Generator, which will generate approximately 165 MW of electricity; (2) a heat recovery steam generator ("HRSG"); (3) a steam turbine generator which will produce an additional 85 MW of electricity; (4) a selective catalytic reduction system for Nitrogen Oxides ("NOx") control; (5) a carbon monoxide ("CO") catalyst; (6) a cooling tower; and (7) a 125-foot exhaust stack (id. at 2-1, 2-9, 7-22; Exhs. HO-E-26; BP-FS-2, at 2-31, 2-32). Additional components include an administration building, a 970,000-gallon fuel storage tank, a 12,000-gallon ammonia storage tank, water tanks and electrical and water treatment equipment (Exhs. BP-1A at 2-9; HO-V-17; HO-E-72). The Company indicated that the most prominent structures associated with the proposed project would be the generation building, the exhaust stack and the cooling tower (Exh. BP-1B at 7-94). The remaining facilities include a variety of smaller buildings and miscellaneous storage tanks, which are less prominent and of an industrial appearance (id.).

The Company's proposed site is located in an industrially zoned area of Agawam (Exh BP-1A at 1-1, 2-3). The northern portion of the proposed site is primarily an open, grassed field and the southern portion is heavily wooded (id. at 2-3). The proposed site is abutted on the north and northeast by wooded and undeveloped, with the exception of two existing 115 kV transmission lines, property owned by WMECo; on the southeast by industrially zoned properties on Industrial Lane and a construction company on Shoemaker Lane; on the south by Shoemaker Lane; on the southwest and west by developed and undeveloped industrially zoned properties; and to the northwest by a lumber company (id. at 2-3 to 2-4).

The proposed project would cost approximately $176 million in 1995 dollars (Exh. HO-RR-6).

The proposed project is being developed by BPD, which is a joint venture of Power Development Company ("PDC"), ABB Energy Ventures, Inc. ("ABB EV"), and Cogeneration Services Corporation ("CSC") (id. at 1-5; Exh. CCBA-RR-2). BPD was formed on May 4, 1995 to manage the development process, execute necessary contracts, and initially hold the permits issued to the project (Exh. CCBA-RR-2). PDC is a privately held company, incorporated in Delaware on April 7, 1993, that develops electrical/energy related projects (Exhs. HO-V-3; HO-V-22). CSC serves the role of ensuring that the proposed project is technically sound, meets all deadlines and stays within budget (Exh. BP-1A at 1-6). CSC also provides development management, community relations and permitting oversight (id.). BPD will establish either a limited partnership (Berkshire Power L.P.) or a limited liability corporation (Berkshire Power LLC) to take ownership of the project sometime prior to financial closing, and will transfer all contracts, obligations and permits acquired during the development process to this new entity (Exh. CCBA-RR-2).

B. Jurisdiction

BPD's petition to construct a bulk generating facility and ancillary facilities was filed in accordance with G.L. c. 164, § 69H, which requires the Siting Board to implement the energy policies in its statute to provide 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 construction permit may be issued by another state agency.

As an independent power plant with a design capacity of approximately 252 MW, BPD'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, BPD'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 June 20, 1995, BPD filed with the Siting Board[1] its proposal to construct a nominal 252-MW natural gas-fired independent power plant and ancillary facilities in the Town of Agawam, Massachusetts. The Siting Board docketed this petition as EFSB 95-1.

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1 Prior to September 1, 1992, the Siting Board's functions were effected by the Energy Facilities Siting Council ("Siting Council"). See Acts of 1992, Chapter 141. As the Siting Council was the predecessor agency to the Siting Board, the term Siting Board should be read in this Decision, where appropriate, as synonymous with the term Siting Council.

On August 17, 1995, the Siting Board conducted a public hearing in Agawam, and on August 30, 1995, the Siting Board conducted a public hearing in Southwick, Massachusetts. In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearings and adjudication.

Petitions to intervene were filed by Chez Josef, Inc. ("Chez Josef"); Springfield Corrugated Box, Inc. ("SCBI"); Concerned Citizens & Businesses of Agawam ("CCBA"); Bay State Gas Company ("Bay State");[2] Cynthia A. and Frank J. Lawlor ("the Lawlors"); Country Estates Nursing Home, Inc. ("Country Estates"); WMECo; Standard Uniform Services ("Standard Uniform"); and U.S. Generating Company ("USGen").[3] Petitions to participate as an interested person were filed by the Connecticut River Watershed Council, Inc. ("CRWC"); Energy Management, Inc. ("EMI"); C.M.F. Engineering, Inc.; and Trout Unlimited, Pioneer Valley Chapter #276 ("Trout Unlimited").

The Hearing Officer allowed the petitions to intervene of Chez Josef,[4] CCBA and WMECo as to any and all matters associated with this proceeding, and the petitions to intervene of SCBI, the Lawlors, Country Estates, and Standard Uniform as to any and all matters associated with environmental impacts and cost. See Hearing Officer Procedural Order, October 11, 1995, at 7-8. The Hearing Officer also allowed the petitions to participate as an interested person of CRWC, EMI, Trout Unlimited, Bay State and USGen. Id. at 8-9; Hearing Officer Procedural Order, October 27, 1995 at 2.

The Siting Board conducted thirteen days of evidentiary hearings commencing January 8, 1996 and ending February 12, 1996. BPD presented eight witnesses: Charles Stankiewicz, vice president of steam turbines and industrial gas turbines with ABB Power Generation, Inc., who testified regarding design and operating characteristics of the generator

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2 Bay State amended its petition to intervene to a petition to participate as an interested person at the Procedural Conference on September 28, 1995.

3 USGen amended its petition to intervene to a petition to participate as an interested person on October 17, 1995.

4 Chez Josef withdrew its petition for intervenor status on November 17, 1995.

turbine; Douglas Corbett, project fuel manager for PDC, who testified regarding fuel procurement strategies; David N. Keast, a consultant in acoustics, who testified regarding noise issues; Frederick M. Sellars, senior program director and manager of the air quality consulting and engineering group at Earth Tech, who testified regarding environmental issues and site selection; Dale T. Raczynski, senior program director for Earth Tech, who testified regarding air quality; Kenneth Roberts, director of development for PDC, who testified regarding the construction and operation of the proposed project and general project matters; Roger M. Cotte, a partner and managing director of R.W. Beck, who testified regarding financing of the proposed project; and Robert Graham, a senior associate with La Capra Associates, who testified regarding the need for the proposed project and alternative technology issues. CCBA sponsored the testimony of one rebuttal witness, Amy Jean Ringuette, who testified regarding issues related to the habitat of the Eastern box turtle in the vicinity of the site.

The Company filed its brief ("Company Brief") and CCBA filed its brief ("CCBA Brief") on March 6, 1996. Country Estates filed a rebuttal brief ("Country Estates Brief") on March 14, 1996. The Company filed its reply brief ("Company Reply Brief") on March 15, 1996.

The Hearing Officer entered 502 exhibits into the record, consisting primarily of information and record request responses. BPD entered 63 exhibits into the record. CCBA entered 31 exhibits into the record. The Lawlors entered 2 exhibits into the record. Trout Unlimited entered 9 exhibits 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 five phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. Cabot Power Corporation, 2 DOMSB 241, 253 (1994) ("Cabot Decision"); Altresco Lynn, Inc., 2 DOMSB 1, 17 (1993) ("Altresco Lynn 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, 2 DOMSB at 18; NEA Decision, 16 DOMSC at 364 (see Section II.C, below). Fourth, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and 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. Cabot Decision, 2 DOMSB at 253; Altresco Lynn Decision, EFSB 91-102, at 11; NEA Decision, 16 DOMSC at 343 (see Section III.A, below). Finally, the Siting Board requires that a proposed project minimize environmental impacts and achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply at the site which is approved. Eastern Energy Corporation (on remand), 1 DOMSB 213, 383-397 (1993) ("EEC (remand) Decision"); Boston Edison Company, 1 DOMSB 1, 149-153, 186-195 (1993) ("1993 BECo Decision") (see Section III.B, below).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

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 City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"), the Supreme Judicial Court ("Court") concluded that the Siting Board's finding that New England needed additional energy resources for reliability purposes was 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 Board 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.

In response to the Court's directive in City of New Bedford, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with its statutory mandate -- to implement the Commonwealth's energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost -- in its EEC (remand) Decision, 1 DOMSB at 421-423.

With respect to the issue of regional need vs. Massachusetts need, 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. Id. at 422. The Siting Board noted the inherent reliability and economic benefits which flow to

Massachusetts as a result of this integration. Id. 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"). Id. at 416. 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 found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision, 1 DOMSB at 417.

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. Cabot Decision, 2 DOMSB at 241, 258, 291-292, 319; Altresco Lynn Decision, 2 DOMSB at 26, 61, 92; 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. Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 19; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes 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. Cabot Decision, 2 DOMSB at 292-300; Altresco Lynn Decision, 2 DOMSB at 61-68; Enron Power Enterprise Corporation, 23 DOMSC 1, 49-62 (1991) ("Enron Decision").

Further, while acknowledging that 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,[5] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Cabot Decision, 2 DOMSB at 259, 291-292; Altresco Lynn Decision, 2 DOMSB at 19, 61; Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985) ("1985 MECo/NEPCo Decision"). 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 the New England Power Pool ("NEPOOL").

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. Cabot Decision, 2 DOMSB at 296-300; Altresco Lynn Decision, 2 DOMSB at 65-68; EEC (remand) Decision, 1 DOMSB at 417-418. 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 for them to be considered in support of a finding of Massachusetts need.

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5 See Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985); 1985 BECo Decision, 13 DOMSC at 70-73.

1 DOMSB at 418. See also, Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost effective qualifying facility ("QF")[6] resources to its utilities' supply mix. NEA Decision, 16 DOMSC at 358. In that case, the Siting Board 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. Thus, in cases where a non-utility developer sought to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board has required 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. Two 1995 decisions of the Court, however, bring into question further reliance on such prima facie evidence in this and future cases.[7]

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6 The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3 ("PURPA"), established a QF category consisting of non-utility electric cogenerators with the capability to generate both electric energy and useable steam. In order to qualify for QF status under PURPA, the cogenerator had to certify to the Federal Energy Regulatory Commission ("FERC") that it would sell a specified portion of its steam byproduct in addition to its electric sales.

7 In Point of Pines Beach Association v. Energy Facilities Siting Board, the Court noted the Siting Board's statutory requirement to make an independent finding of Commonwealth need, a finding that could not be premised solely on the existence of signed and approved PPAs. Point of Pines Beach Association v. Energy Facilities Siting Board, 419 Mass. 281, 285-286 (1995) ("Point of Pines"). Referencing its (continued...)

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. Cabot Decision, 2 DOMSB at 259; Altresco Lynn Decision, 2 DOMSB at 27; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision"). Therefore, consistent with the Siting Board's precedent and reflecting the directives of the Court in City of New Bedford, Point of Pines, and Attorney General, the Siting Board here reviews the need for the proposed project for capacity, economic and environmental purposes.

2. Capacity Need

The Siting Board has found that it is appropriate to consider the need for capacity beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See Cabot Decision, 2 DOMSB at 289-290; Altresco Lynn Decision, 2 DOMSB at 58-59; West Lynn Decision, 22 DOMSC at 14, 33-34. The Siting Board has acknowledged that 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. Thus for the purposes of this review, the Siting Board

[7](...continued)
decision in Point of Pines, the Court vacated a final decision of the Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) ("Attorney General").

finds that it is appropriate to explicitly consider need for the proposed facility during the 1998/1999 to 2002 time period.

a. New England

BPD asserted that there is a need for at least 252 MW of additional energy resources in New England beginning in the year 1999 and beyond (Company Brief at 28). In support, the Company presented a series of forecasts of demand and supply for the region, based primarily on the 1993, 1994 and 1995 forecasts and other data published by NEPOOL. The Company stated that it compared its demand and supply forecasts to produce a series of need forecasts (Exh. BP-RG-1, at 13-14).

In the following sections, the Siting Board reviews the Company's demand forecasts, including its demand forecast methods and estimates of demand side management ("DSM") savings over the forecast period, and the Company's supply forecasts, including its capacity assumptions and required reserve margin assumptions. The Siting Board then analyzes a series of need forecasts.

i. Demand Forecasts

(A) Description

BPD presented a range of forecasts of unadjusted summer and winter peak load and DSM savings, derived primarily from information contained in the 1993, 1994 and 1995 Capacity, Energy, Loads and Transmission ("CELT") reports, published by NEPOOL (Exhs. BP-1A at 3-5; BP-RG-1, at 2-5).[8] The Company presented six forecasts of

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[8] The Company indicated that the CELT reports include: (1) a high, reference and low forecast of unadjusted load for summer and winter peaks; (2) a forecast of DSM savings; (3) a forecast of NUG netted from load (i.e., power from NUG units located at the site of an end-user which displace power that could be sold by a NEPOOL utility, which is not available for sale outside the site); and (4) a reference forecast of adjusted load for summer and winter peaks, derived by deducting the forecasts of DSM savings and NUG netted from load from the unadjusted reference load forecast (Exhs. HO-RN-1(atts. a, b, & i); HO-RN-4(att. a); Tr. 6, at 66-67).

unadjusted summer peak load and five forecasts of unadjusted winter peak load (Exhs. BP-RG-1(atts. 3, 4); HO-RR-29). To develop forecasts of adjusted load, the Company combined these demand forecasts with (1) the 1995 CELT report forecast of NUG netted from load, and (2) three forecasts of DSM savings based on the 1995 CELT report forecast of DSM savings (Exhs. BP-RG-1(atts. 3, 4); HO-RR-29). Overall, the Company provided sixteen forecasts of adjusted summer peak load and thirteen forecasts of adjusted winter peak load (Exhs. BP-RG-1, atts. 3, 4; HO-RR-29).

(1) Demand Forecast Methods

The Company stated that three summer and three winter unadjusted peak load forecasts were derived directly from the NEPOOL CELT report reference forecasts of unadjusted load for summer and winter peak for the years: (1) 1993 ("1993 CELT forecast"); (2) 1994 ("1994 final CELT forecast"); and (3) 1995 ("1995 CELT forecast") (Exhs. BP-1A at 3-9, 3-13; BP-RG-1, at 2-5). The Company stated that it also derived summer and winter peak load forecasts directly from an initial CELT reference forecast prepared in 1994 ("1994 initial CELT forecast") (Exh. BP-1A at 3-12).[9]

BPD stated that it developed two further load forecasts based on actual peak loads experienced in 1994 (Exhs. BP-1A at 3-10 to 3-12; HO-RR-29).[10] The first of these

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9 The Company indicated that, prior to issuing the 1994 CELT report, NEPOOL produced an initial load forecast which was higher than the forecast included in that CELT report (Exh. BP-1A at 3-12 to 3-13). The Company asserted that the NEPOOL Policy Planning Committee revised this 1994 initial CELT forecast downward in response to concerns that the forecast was higher than the sum of the individual member utilities' forecasts (Exhs. HO-RN-4, at 2, HO-RN-4(att. a)). The 1994 final CELT forecast was included in the 1994 CELT report (id.; Exh. HO-RN-1(att. b)).

10 The Company considered three different "actual" summer peak loads for 1994: (1) the highest, reconstituted summer peak load which was weather-normalized amounting to 20,534 MW ("actual peak, weather-normalized"); (2) the highest weather-normalized peak load of 21,138 MW; and (3) an average of the (continued...)

forecasts escalates the 1994 summer highest weather-normalized peak of 21,138 MW by the growth rates predicted in the 1994 final CELT forecast ("1994 normalized CELT forecast") (Exh. BP-1A at 3-10 to 3-12). The second forecast, characterized by the Company as the most likely forecast, escalates the 1994 summer and winter actual peaks, weather-normalized by 2.5 percent per year ("1994 normalized 2.5 percent forecast") (Exh. HO-RR-29).[11] The Company also provided summer and winter forecasts starting from the average peaks (Exh. HO-RR-29). Inasmuch as these forecasts were provided after the close of hearings and the Company discusses only the 1994 normalized 2.5 percent forecast in its Brief (see

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[10](...continued)

weather-normalized peak load ("average peak") based on 32 summer peak candidate days amounting to 20,200 MW (Exhs. HO-RN-1(att. K at 11); BP-1A at 3-11; Tr. 6, at 45-46).

With respect to winter peak load, the Company stated that: (1) the actual peak, weather normalized was 19,093 MW; (2) the highest weather normalized peak was 19,869 MW; and (3) the average peak, based on 22 peak candidate days, was 19,250 MW (Exh. HO-RN-1(att. k at 11)).

The Company noted that NEPOOL reports the average peak as the seasonal peak load (Tr. 6, at 45-46). However, Mr. Graham stated that it was not appropriate to determine a peak day by the average of candidate peak days, because the method of selecting peak days to average would determine the results (id. at 47-48). He added that by choosing to include lower temperature-humidity days in the average, NEPOOL lowered the average peak (id. at 48-49). The Company indicated that the 1992 summer peak reported by NEPOOL was based on the reconstituted peak of one day and that the 1993 winter peak reported by NEPOOL was an average peak of 12 days (Exh. HO-RR-43(att. a at 11)).

[11] The Company stated that, because the actual peak, weather-normalized and highest weather-normalized peak reflect the effects of DSM and NUG netted from load, it was necessary to estimate the unadjusted load for 1994 by adding the amounts of DSM and NUG netted from load in the 1994 CELT report to the 1994 weather-normalized peak (Exhs. BP-1A at 3-11; HO-RR-29, at 1, n.1). The Company also stated that (1) unadjusted load was then escalated annually, and (2) projected DSM and NUG netted from load were then subtracted to obtain a forecast of adjusted load (Exhs. BP-1A at 3-11; HO-RR-29, at 1, n.1).

Company Brief at 38-39), the Siting Board does not consider the forecast based on average peaks in its review of regional need.

The Company stated that all its forecasts were adjusted to incorporate the addition of Nantucket Electric Company ("NEC") load to NEPOOL beginning in 1997 (Exhs. BP-1A at 3-7, 3-9 to 3-10; HO-RN-2).

The Company asserted that the 1994 normalized 2.5 percent forecast represents a reasonable base case demand forecast because it reflects the current consensus economic growth outlook for the region and the historic linkage between economic growth and load growth in the region (Exh. HO-RR-29; Company Brief at 31-32). In addition, the Company asserted that the 1993 CELT forecast and the 1994 normalized CELT forecast represent reasonable high case demand forecasts and that the 1994 initial CELT forecast represents a reasonable low case demand forecast (Company Brief at 31-32). The Company further asserted that the 1994 final CELT forecast and the 1995 CELT forecast are based on inappropriate assessments of regional load growth and that these forecasts therefore should not be given any weight in the Siting Board's overall assessment of regional need (id. at 32, 37). Although the Company indicated its preference for the methods used in the 1993 CELT forecast, the Company acknowledged that the 1993 forecast is based on dated information (Tr. 6, at 6).

In support of its assertions, the Company stated that (1) the long-run forecasting model[12] used to develop the 1994 and 1995 CELT forecasts incorporated questionable changes in assumptions, and (2) the 1994 and 1995 CELT forecasts underforecast actual summer peak loads (Exhs. BP-1A at 3-16; BP-RG-1, at 4; HO-RN-4; Company Brief at 32-37). With respect to NEPOOL's long-run forecasting model, BPD noted that the 1993

[12] BPD explained that, in developing demand forecasts, NEPOOL: (1) produces a short-term forecast for the first two years of the forecast period using a set of econometric models; (2) produces a long-term forecast starting in the fifth year of the forecast period based on a set of end-use models; and (3) blends the results of the short-term and long-term forecasts for the third and forth years of the forecast period (Exh. BP-RG-1, at 3).

CELT forecast was produced using the same long-run modeling assumptions as the 1992 CELT forecast, a forecast the Siting Board has accepted in a number of previous proceedings (Exh. BP-1A at 3-10). BPD claimed that in 1994, NEPOOL made a number of unjustified changes to the methods used in the long-run forecasting model which were designed to produce an unreasonably low forecast, including adjustments to: (1) air conditioning penetration rates; (2) the commercial productivity variable;[13] and (3) the forecast of economic growth[14] (Exh. HO-RN-4; Company Brief at 32).

BPD indicated that the changes in the commercial productivity variable and the forecast of economic growth were reflected in the 1994 initial CELT forecast, while the changes in air conditioning penetration rates were made between the 1994 initial and final CELT forecasts (Exhs. BP-RG-1, at 3; BP-1A at 3-12 to 3-13). BPD stated that since NEPOOL did not update its long-run forecast for the 1995 CELT forecast,[15] the 1995 CELT forecast also reflects all three changed assumptions (Exh. BP-RG-1, at 3). The Company indicated that NEPOOL considered the change in air conditioning penetrations to have the greatest impact on summer peak load (Company Brief at 33, citing,

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13 BPD explained that the commercial productivity variable, which is an employment-based variable adjusted for projected changes in commercial labor productivity, is the major driver of the commercial sales forecast (Exh. HO-RN-4). BPD indicated that beginning in 1994, NEPOOL used a partial productivity adjustment rather than the full productivity adjustment used in previous years (id.). The Company maintained that this reduction was unjustified given that both employment and the partially adjusted commercial activity driver have grown at a slower rate than commercial electricity sales over the past decade (id. (att. d)).

14 BPD stated that the economic forecast underlying the 1994 and 1995 CELT forecasts is overly conservative in that actual growth in Gross State Product, real personal income and employment have generally been greater than NEPOOL's projections (Exh. HO-RN-4).

15 BPD explained that NEPOOL prepared a new short-term forecast for the years 1995 and 1996, and combined this updated short term forecast with the long-term forecast from the 1994 final CELT forecast (Exh. BP-RG-1, at 3).

Exh. HO-RN-1).[16] BPD explained that the 1993 CELT forecast and 1994 initial CELT forecast assume that air conditioning penetrations will increase over time, consistent with growth in real personal income, but that the 1994 final and 1995 CELT forecasts assume that (1) residential air conditioning penetration would increase slightly from 1993 to 1994 and then remain constant over the forecast period, and (2) commercial new construction air conditioning penetration would decline from 1993 to 1994 and then remain constant over the forecast period (Exh. HO-RN-4, at 2).[17] The Company asserted that these assumptions were unwarranted based on: (1) 1994 and 1995 summer peak load data; (2) press reports of high rates of air conditioner purchases; and (3) NEPOOL's own statements regarding "an increasing dominance of commercial and residential air conditioning load" during summer peak periods (id. at 2-3; Tr. 6, at 15).[18]

The Company stated that NEPOOL summer peak loads are largely driven by air conditioning load, and that if air conditioning penetrations increase, the summer peak loads would be significantly higher than those forecast in the 1994 final CELT and 1995 CELT reports (Exhs. HO-RN-4, at 3; BP-1A at att. 3-5).[19] The Company asserted that the 1994

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16 The Company stated that the NEPOOL load forecasting committee "decided to lower projected penetration rates of residential and commercial air conditioning to reflect more closely current company expectations of marketplace conditions" (Tr. 6, at 12-13). The Company was unable to provide commercial air conditioning penetration forecasts for the major Massachusetts electric utilities (Exh. HO-RR-25).

17 The Company indicated that the 1994 final CELT forecast assumes that air conditioning penetration in new Massachusetts office buildings, restaurants, retail buildings and warehouses would decline by 25 percent from 1993 to 1994 and then remain constant over the forecast period (Exhs. HO-RN-4, at 2; HO-RN-4(att. c)).

18 The Company noted that, in larger commercial buildings, electric air conditioning may face some competition with gas air conditioning but that gas air conditioning would not likely be installed in smaller commercial or residential buildings (Tr. 6, at 12-13).

19 The Company also provided an assessment of air conditioning penetration trends using a time series regression analysis of air conditioning penetration on real personal (continued...)

initial CELT forecast, which does not incorporate the new air conditioning penetration rates, avoids a significant weakness in the 1994 final and 1995 CELT forecasts (Exhs. BP-1A at 3-12; BP-RG-1, at 3).

The Company also asserted that both the 1994 final CELT forecast and 1995 CELT forecast underforecast actual summer peak loads in the short term and medium term (Exhs. BP-1A at 3-16; BP-RG-1, at 4; Company Brief at 37). BPD stated that the 1994 summer highest weather-normalized peak exceeded the 1994 final CELT forecast's projections of summer peak through 1999 and the 1995 CELT forecast's projections of summer peak through 1998 (Exhs. BP-1A at 3-16 to 3-17; BP-RG-1, at 4).[20] The Company noted that the 1993 CELT forecast and 1994 initial CELT forecast also underforecast actual summer peak in both the short term and medium term (Exh. BP-1A at 3-12 to 3-13, 3-16 to 3-17).

The Company noted that the 1994 final CELT forecast of winter peak load corresponded well with the actual winter weather-normalized peak for 1994/1995 (Exh. BP-1A at 3-10, n.5). Therefore, the Company did not prepare a 1994 normalized CELT forecast for winter peak load (id.).

(2) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the forecast of company-sponsored DSM savings used in NEPOOL's 1994 and 1995 CELT reports; (2) a high DSM scenario, which assumes an increase of ten percent in the annual

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[19](...continued)
income (Exh. HO-RN-44). The Company stated that this assessment demonstrates that air conditioning penetration is likely to be higher than NEPOOL's forecast over the long term (id.).

[20] Although official data from NEPOOL was not available regarding the 1995 summer peak, the Company stated that NEPOOL has indicated that 1995 summer peak would be similar to, and perhaps slightly higher than, the 1994 summer peak (Exh. HO-RN-7).

post-1994 growth rate of the base scenario; and (3) a low DSM scenario, which assumes a decrease of 25 percent in the annual post-1994 growth rate of the base scenario (Exhs. BP-1A at 3-13 to 3-15; BP-RG-1, at 13). The Company asserted that the base DSM scenario likely overstates DSM savings achievable in the region and that, based on up-to-date data and studies, the low DSM scenario is the most likely forecast of future DSM savings (Tr. 6 at 136-137; Company Brief at 41).

In support of this assertion, the Company stated that, although NEPOOL has consistently revised its forecasts of company-sponsored DSM savings downward in each successive CELT report from 1990 to 1994, NEPOOL has continued to significantly overestimate DSM savings experienced by its member utilities (Exhs. BP-1A at 3-14, n.6; HO-RN-8, at 1; HO-RN-8(att. a)). As an example, the Company indicated that NEPOOL's actual 1993 summer DSM savings were 918 MW (Exh. HO-RN-8(att. a)). The 1990 CELT forecast projection of 1993 summer DSM was 1420 MW, an overprojection of 54.7 percent (id.). This projection was lowered in each successive CELT report until a projection of 1002 MW, an overprojection of nine percent, was made in 1994 (id.). Actual summer DSM savings for 1994 were not provided, but the Company indicated that NEPOOL also lowered its forecast of 1994 summer DSM savings from 1647 MW in the 1990 CELT report to 1034 MW in the 1994 CELT Report (id.). In addition, the Company indicated that over the 1991 through 1994 time period, the combined DSM savings of Massachusetts investor-owned utilities were less than projected savings (id.). The Company further indicated that a number of utilities in the region recently have reduced their DSM budgets and that a number of existing DSM programs will no longer be considered cost-effective due to the Court decision regarding environmental externalities (Exhs. HO-RN-8; HO-RN-4). See Massachusetts Electric Company v. Department of Public Utilities, 419 Mass 239 (1994).

(B) Analysis

BPD developed four summer and four winter demand forecasts based directly on the 1993, 1994, and 1995 CELT report reference forecasts and the initial 1994 CELT reference forecast. In addition, the Company developed two summer demand forecasts based on escalation of the 1994 summer peak by two different methods and one forecast based on the escalation of the 1994/1995 winter peak.

The Siting Board notes that it previously has acknowledged that the CELT report generally can provide an appropriate starting point for resource planning in New England, and has accepted the use of CELT forecasts for the purposes of evaluating regional need in previous reviews of proposed NUG facilities. Cabot Decision, 2 DOMSB at 273-274; Altresco-Lynn Decision, 2 DOMSB at 43; NEA Decision, 16 DOMSC at 354. Here, the Company provided demand forecasts based on four CELT forecasts from a three year period. The assumptions and methods varied primarily between the 1993 forecast and the later forecasts. Although the Company considered the assumptions and methods of the 1993 CELT forecast to be preferable to the more recent CELT forecasts, the Company acknowledged that the 1993 CELT forecast was based on dated information.[21] Nonetheless, since the record in this proceeding includes more recent CELT forecasts, the Siting Board will rely primarily on the more recent forecasts in its analysis of regional need in this proceeding.

In considering the remaining demand forecasts, the Siting Board examines first the forecasts of summer peak load, and then the forecasts of winter peak load. The Siting Board notes that because NEPOOL did not update its long-run forecast method for the 1995 CELT forecast, the 1994 final CELT forecast and the 1995 CELT forecast are identical in the years 1999 and beyond. Given that the Siting Board's consideration of need in this case focuses on a period of several years beginning in 1999, the initial years of projected operation assuming the proposed 1999 start-up date, it would be duplicative to include both the 1994 final CELT forecast and the 1995 CELT forecast in the consideration of summer need. Therefore, the Siting Board includes only the 1995 CELT forecast in its consideration of summer need.

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21 As a general principle, the Siting Board notes that it can find no reason to reject conclusions based on forecasts, due solely to the age of the forecast, without evidence that the information on which the forecast is based is no longer accurate.

The Siting Board notes that the primary difference between the long-run forecasts underlying the 1994 initial CELT forecast and the 1995 CELT forecast is the air conditioning penetration assumptions. NEPOOL assumed in the 1994 initial CELT forecast that commercial and residential air conditioning penetrations would increase with growth in personal income, but assumed in the 1995 CELT forecast that residential and commercial air conditioning penetrations would increase slightly or decrease in the first year of the forecast and then remain flat in later years. The Siting Board agrees with the Company that the air conditioning penetration assumptions included in the 1994 initial CELT forecast appear to be more reasonable than those included in the 1995 CELT forecast. Consequently, the Siting Board considers the 1994 initial CELT forecast, which is in essence the 1995 CELT forecast with an adjustment for air conditioning penetrations, to be an appropriate base case summer forecast.

Accordingly, the Siting Board finds that the 1994 initial CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond. The Siting Board considers it appropriate to include the most recent CELT peak load forecast, the 1995 CELT forecast, in its consideration of regional need. Accordingly, the Siting Board finds that the 1995 CELT forecast is an appropriate low case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond.

With respect to the two summer peak load forecasts based on the escalation of "actual" 1994 summer peaks, the Company characterized the 1994 normalized 2.5 percent forecast as a reasonable base case forecast and the 1994 normalized CELT forecast as a reasonable high case forecast. The Siting Board notes that both forecasts combine a modeled future year growth trend with an adjusted base year peak load level reflecting a single recent year. This approach ignores the cyclical nature of the economy. For instance, both forecasts could predict inflated peak load over the long term if the actual 1994 peak load were at the high point of an economic cycle.[22]

Further, with respect to the 1994 normalized 2.5 percent forecast, the Siting Board notes that in previous cases it has reviewed forecasts based on an analysis of the historical relationship of an economic indicator and peak load. The Siting Board accepted such forecasts as alternative forecasts in evaluations of regional need but recognized that such forecasts were based on methods that are less sophisticated than other forecasts such as the CELT forecast. See Cabot Decision, 2 DOMSB at 276-277; Altresco Lynn Decision, 2 DOMSB at 47; EEC Decision, 22 DOMSC at 236-237. Here, the Company has not provided a forecast based on an analysis of the historical relationship of an economic indicator and peak load, but rather has assumed that the actual 1994 summer peak load would grow at 2.5 percent per year over the forecast period based on "current expectations of economic growth." Further, the Company has not provided either data regarding a historical relationship between peak load growth and economic growth, or sufficient substantiation of its assertion that the economy will continue to grow at an annual rate of 2.5 percent over the forecast period. Thus, the Siting Board finds that the 1994 normalized 2.5 percent forecast

22 Additionally, we note that, by using the highest weather normalized peak and the actual peak, weather normalized as starting points for its 1994 normalized CELT forecast and the 1994 normalized 2.5 percent forecast, respectively, the Company incorporated 1994 normalized peak load values that exceed those recognized by NEPOOL by 314 MW for the 1994 normalized 2.5 percent forecast and by 918 MW for the 1994 normalized CELT forecast. As justification, the Company argues that NEPOOL's approach of using an average of candidate days to determine normalized peak load by season is affected by the number of candidate days included in the average. The Siting Board does not disagree with the Company's observation, and notes NEPOOL's method could include so large a range of candidate days that the reported peak load is biased downward. We note that in 1994, NEPOOL reported a summer peak based on one peak day, and are concerned that this lack of consistency may contribute to bias in NEPOOL's reported peak load. However, since we do not know the extent of any potential bias in NEPOOL's reported 1994 summer peak, we are hard-pressed to accept BPD's suggested use of the single day peak as an appropriate adjustment.

is not an acceptable summer peak load forecast for use, here, in an analysis of regional demand.

However, the Siting Board recognizes that the CELT report-based forecasts that BPD has presented underforecast actual summer peak loads in the short-term. Thus, while acknowledging that the 1994 normalized CELT forecast may be inflated over the long-term, the Siting Board finds that the 1994 normalized CELT forecast is a possible high-case summer peak load forecast for use in an analysis of regional need for the years 1999 and beyond.

In considering the Company's forecasts of winter peak load, the Siting Board first notes that, due to the anticipated January 1, 1999 start-up date of the proposed project, review of winter need should begin with the 1998/1999 winter. The Siting Board further notes that its primary criticism of the 1995 CELT forecast was the air conditioning penetration assumptions reflected in that forecast. Given that air conditioning penetration assumptions do not have an impact on the winter peak load forecast, the Siting Board's criticism of the 1995 CELT's forecast of summer peak load does not extend to the forecast of winter peak load. Accordingly, the Siting Board finds that the 1995 CELT forecast is an appropriate base case winter peak load forecast for use in the analysis of regional need for the years 1998/1999 and beyond.

The Siting Board's concerns regarding the 1994 normalized 2.5 percent forecast are the same for both summer and winter peak load. Thus, the Siting Board finds that the 1994 normalized 2.5 percent forecast is not an acceptable winter peak load forecast for use, here, in an analysis of regional demand.

As noted above, the 1995 CELT forecast and the 1994 final CELT forecast are identical, beginning in the year 1999, and the most significant difference between the 1995 CELT forecast and the 1994 initial CELT forecast are assumptions related to air conditioning penetrations. Inasmuch as the 1995 CELT forecast has been accepted as a base case winter peak load forecast, it would be duplicative to include either the 1994 initial CELT forecast or

1994 final CELT forecast in an analysis of winter peak load. Consequently, the Siting Board will consider only the 1995 CELT forecast of winter peak load.[23]

Finally, the Company provided three forecasts of DSM -- a base scenario which is the most current NEPOOL forecast of DSM, a low scenario which discounts NEPOOL's projected DSM increases over 1993 levels by 25 percent, and a high scenario which inflates NEPOOL's projected DSM increases over 1993 levels by 10 percent. Although the Company considered the low DSM scenario to be an appropriate base case, the Company did not clearly specify why the 25 percent reduction in projected DSM growth rates was appropriate. The Siting Board recognizes that previous NEPOOL forecasts of company-sponsored DSM have exceeded actual DSM savings. However, between 1990 and 1994, NEPOOL has consistently lowered its forecast of company-sponsored DSM. Relative to the 1990 CELT forecast, NEPOOL had decreased its forecast of 1993 DSM savings by 29.4 percent as of the 1993 CELT forecast and had decreased its forecast of 1994 DSM savings by 37.2 percent as of the 1994 CELT forecast. NEPOOL's overprediction of actual 1993 DSM savings decreased from 54.7 percent in the 1990 CELT forecast to nine percent in the 1993 CELT forecast. Thus, NEPOOL's forecast of DSM savings have consistently decreased, and in recent years have come significantly closer to actual DSM savings.

The Siting Board also recognizes that a number of Massachusetts investor-owned utilities have overpredicted actual DSM savings and that a number of regional utilities have decreased their DSM budgets in recent years. However, it is not clear from the record in this case: (1) how the individual utilities forecast DSM savings over the long-term; (2) how individual utility forecasts of DSM are incorporated into the NEPOOL regional forecasts; or (3) whether NEPOOL takes into account the possibility of utility over-predictions and DSM budget reductions in forecasting DSM savings over the long-term.

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23 Given uncertainties in forecasting demand, the Siting Board recognizes that it is reasonable to include a range of forecasts in its review of a Company's need analysis for a proposed project. Since the Siting Board has accepted a range of forecasts of summer peak load, it is acceptable, in the instant proceeding, to consider only one forecast of winter peak load.

Thus, in this case, the Siting Board does not consider it appropriate to adjust NEPOOL's most current forecast of Company-sponsored DSM in the base case. Accordingly, for the purposes of this review, the Siting Board finds that NEPOOL's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis.

In addition, the Siting Board agrees with the Company that there is a greater likelihood that company-sponsored DSM savings will be lower than what is predicted in the base case forecast rather than higher than what is predicted in the base case forecast. Thus, the Siting Board finds that the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis. The Siting Board also finds that the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis.

In sum, the Siting Board has accepted three forecasts of summer peak load -- the 1994 initial CELT forecast as a base case forecast, the 1995 CELT forecast as a low case forecast, and the 1994 normalized CELT forecast as a high case forecast -- and one forecast of winter peak load -- the 1995 CELT forecast as a base case forecast. In addition, the Siting Board has accepted three forecasts of DSM -- a base case, low case and high case. Each of the forecasts of peak load is adjusted by each of the three forecasts of DSM. Therefore, overall, the Siting Board reviews nine forecasts of adjusted summer peak load and three forecasts of adjusted winter peak load.

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

BPD presented three supply scenarios based on the capacity projections in the 1995 CELT report -- a base supply scenario, a high supply scenario, and a low supply scenario

(Exhs. BP-RG-1 at 5-13; HO-RR-29).[24] The Company asserted that the low supply scenario should be considered the most likely forecast of supply for the region (Exh. HO-RR-29; Company Brief at 43-44).

Mr. Graham stated that the base supply scenario reflects the resources included in the 1995 CELT Report,[25] updated to incorporate current information on actual and planned changes to NEPOOL supply (Exh. BP-RG-1, at 6). The Company stated that it made reductions to the 1995 NEPOOL supply projections to reflect: (1) the retirement of the Salem Harbor 1-3 units (303 MW summer, 305 MW winter) beginning in 1999; (2) removal of unsold portions of existing generation projects whose capacity is partially or wholly uncommitted at present (290 MW summer, 311 MW winter); (3) the outage of the Maine Yankee unit for a 12-month period beginning in March 1995 (870 MW summer, 880 MW winter); (4) the derating of the Maine Yankee unit by ten percent beginning in 1996 (87 MW summer, 88 MW winter); (5) utility buy-outs of NUG projects (ranging from 58 MW to 146 MW, summer and winter, over the forecast period); and (6) the removal of the capacity of the proposed Taunton Energy Center ("TEC") beginning in 1998 (150 MW summer and winter)[26] (Exhs. BP-RG-1, at 6-8; HO-RR-29). The Company stated that it made additions to the 1995 NEPOOL supply projections to reflect (1) incorporation of 75 percent of the

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24 The Company provided separate summer and winter supply scenarios to account for the seasonal variation in the capacity rating of various NEPOOL units (Exh. BP-1A at 3-19, n.10).

25 The Company indicated that NEPOOL counts toward capability all existing plants, external purchases and sales, and committed utility and non-utility generation owned or contracted by NEPOOL member utilities (i.e., all non-utility generating units that are under construction and/or fully licensed, including any contract changes) (Exhs. BP-RG-1, at 6; HO-RN-1(att. i at 55)).

26 The Company indicated that the 1995 CELT Report included the TEC coal-fired project as committed capacity in 1998 under category "T" which signifies "regulatory approval received including building permit, not under construction" (Exhs. BP-RG-1, at 9; HO-RN-1(att. i at 33, 54)). The Company stated that it removed the TEC project from committed capacity due to the pendency of the project's petition before the Siting Board and the current projected on-line date of 2000 (id.).

contracted capacity in New England Electric Systems' ("NEES") Green RFP beginning in 1996 (27 MW summer and winter),[27] and (2) inclusion of the NEC supply remaining on-island beginning in 1997 (15 MW summer, 16 MW winter) (Exhs. BP-RG-1, at 6-8; HO-RR-29). In addition, consistent with NEPOOL assumptions, the Company stated that it assumed that the Hydro-Quebec Phase II ("HQ II") contract, which expires in June 2001, would not be renewed but that the HQ II transmission line would continue to provide reliability benefits with a capacity value of 85 percent of its current capacity (Exh. BP-1A at 3-20 to 3-21).[28]

In explaining its changes to the 1995 NEPOOL supply projections, the Company asserted that NEES plans to retire the coal-fired Salem Harbor 1-3 units (Exhs. BP-1A at 3-19; HO-RN-16(att. d)). In support of this explanation, the Company provided a copy of (1) the resource summary table from Massachusetts Electric Company's ("MECo")[29] most recent IRM filing in D.P.U. 94-112, which indicates that the units will be retired in the year 2000, and (2) a response to a data request in a 1994 Granite State Electric Company proceeding before the New Hampshire Public Utilities Commission, which indicates that the

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27 BPD stated that 75 percent rather than 100 percent of the contracted 36 MW under the NEES Green RFP was included to reflect the likelihood that not all projects will be built and uncertainties associated with developing new technologies (Exh. HO-RN-11). The Company noted that there has been significant environmental opposition to the Kenetech windpower project, which accounts for a large amount of the Green RFP capacity (id.).

28 The Company stated that, consistent with NEPOOL assumptions set forth in the June 1994 Generation Task Force Assumption Book ("1994 GTF"), beginning in 2001, the base case supply scenario assumes a reduction in the capacity value of the HQ II transmission line from 1,500 MW to 1,270 MW in the summer, and from 525 MW to 430 MW in the winter (Exhs. BP-1A at 3-21; HO-RN-14). BPD noted that the reliability benefits of the HQ II transmission line could be represented as a supply resource or as a reduction in required reserves (Exh. BP-1A at 3-20 to 3-21).

29 MECo is a subsidiary of NEES.

units will be retired in 1999[30] (Exh. HO-RN-10). The Company indicated that the initial year of operation for the Salem Harbor 1-2 units was 1952 and that the initial year of operation for the Salem Harbor 3 unit was 1958 (Exh. HO-RN-16(att. d)). The Company noted that the NEPOOL retirement guideline for coal-fired units is 40 years (id.).

With respect to uncommitted existing supply, the Company stated that this category includes two existing generation projects -- the Enron generating facility and the Great Bay Power project, which owns a portion of the Seabrook facility (Tr. 6, at 94). Mr. Graham asserted that the full capacity of the Enron facility (150 MW summer, 171 MW winter) is uncommitted but that the facility is operating and selling power to the short-term market (Exh. HO-RR-29; Tr. 6, at 96-97). He further stated that Enron recently joined NEPOOL and that the facility therefore is dispatched based on variable cost and availability, like other NEPOOL units (Tr. 6, at 98). Mr. Graham stated that the Great Bay Power project (140 MW summer and winter), which also has no long-term power sales agreements and sells power on the short-term market, is available whenever the remaining portion of the Seabrook facility is available (Exhs. HO-RR-29; HO-RR-43; Tr. 6, at 98). Mr. Graham explained that both projects are competing with the proposed project for power sales contracts and thus should not be considered committed resources for the purposes of determining capacity need (Exh. HO-RR-42). However, he noted that the full capacity of both the Enron and Great Bay Power projects is included in the Company's dispatch analysis (Exhs. HO-RN-35; HO-RN-44) (see Section II.A.3.a.i, below). The Company asserted that its treatment of uncommitted existing supply is consistent with Siting Board precedent (Exh. HO-RR-42).

With respect to buy-outs of NUGs, BPD explained that recent utility buyouts of NUG projects that were not incorporated into the 1995 CELT report include: (1) the Fairfield Energy Venture ("FEV"), 32 MW summer and winter; (2) O'Brien, 54 MW summer and

30 The Company also provided a copy of an undated response to a data request in a Narragansett Electric Company proceeding before the Rhode Island Public Utilities Commission which indicated that the Company's probabilistic need assessment included the Salem Harbor 1-3 units as "at risk" capacity for early retirement (Exh. HO-RN-10).

winter;[31] (3) Pepperell, 31.4 MW summer, 37.2 MW winter; (4) Ultrapower 5, 24.9 MW summer, 25.1 MW winter; and (5) Ultrapower 6, 24.9 MW summer, 25.1 MW winter (Exhs. BP-RG-1, at 7-8; HO-RR-29(att. a)).[32] Mr. Graham stated that the FEV facility is still operating but that the other facilities are currently shut down (Tr. 6, at 101-104).[33] He stated that the capacity of the FEV facility was deducted from 1995 NEPOOL supply beginning in late 1997 to reflect the likelihood that Central Maine Power ("CMP") will close the facility due to high costs (Tr. 6, at 102).[34]

Finally, with respect to the derating of the Maine Yankee facility over the forecast period, the Company provided documentation from the Nuclear Regulatory Commission ("NRC") that the unit has been derated by 10 percent due to uncertainties related to the emergency core cooling system and containment analysis and that said derating will continue until the NRC reviews and approves new analyses (Exh. HO-RR-30). The Company asserted

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[31] Mr. Graham stated that the buyout by Northeast Utilities ("NU") of its power purchase agreement with the 54 MW O'Brien unit was facilitated by a power marketer who will sell an equal amount of replacement power to NU at a lower price (Exh. BP-RG-1, at 7, n.1). He stated that the source of the replacement power is confidential and that therefore, only 50 percent of the 54 MW capacity of the O'Brien unit was deducted to reflect the possibility that a portion of the replacement power would come from outside NEPOOL (Tr. 6, at 100-101).

[32] BPD indicated that the 1995 CELT report reflects the buyouts of the Ashland, Beaverwood, Lowell, Alexandria and Timco NUG units, none of which are presently operating (Exh. BP-RG-1, at 7; Tr. 8, at 72).

[33] Mr. Graham stated that it is possible that the Pepperell facility has been bought by an entity that is interested in continuing to operate the facility, but that it is not clear whether it will be economic to do so (Tr. 6, at 102-103).

[34] Mr. Graham stated that the FEV facility was bought out by CMP, which planned to close it due to high operating costs, but that, in accordance with an agreement reached with the local town, CMP will keep the facility operating for three years and then reassess the economic situation (Tr. 6, at 102). He noted that it was likely that the facility would be closed after the three-year period due to the facility's high costs (id.).

that the facility may have been operating at an unsafe capacity level and that the derating may continue indefinitely and may become permanent (id.).

For the low supply scenario, the Company assumed reductions to the base supply scenario to reflect: (1) the permanent retirement of all presently deactivated plants scheduled for reactivation in the 1995 CELT Report beginning in 2002 (227 MW summer, 229 MW winter); (2) the retirement of 50 percent of all coal-fired and oil-fired capacity operating beyond NEPOOL retirement guidelines beginning in 1999 (144 MW increasing to 1,020 MW summer, 171 MW increasing to 1097 MW winter);[35] and (3) the reduction in the capacity value of the HQ II transmission line to 50 percent of its present value beginning in 2001 (Exh. BP-RG-1, at 9-10).

The Company asserted that, compared to the base supply scenario, the low supply scenario represents a realistic assessment of the continuing availability of older NEPOOL units and the capacity value of an unbooked HQ II transmission line (Company Brief at 43, citing, Exh. BP-1A at 3-24). In support, BPD stated that a significant portion of the existing NEPOOL fossil-fired capacity has exceeded or will soon reach NEPOOL's plant retirement guidelines (Exhs. BP-1A at 3-23; HO-RN-16). BPD further stated that, contrary to NEPOOL assumptions that these units will continue to operate, a number are likely to be retired within the forecast period given increasing operating costs, equipment breakdown, and incremental capital costs, particularly related to increasing emission control requirements (Exhs. BP-1A at 3-23; HO-RN-18).[36] Mr. Graham also stated that the move to a

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35 The Company assumed that existing coal-fired capacity would be retired if it reached or was operating beyond NEPOOL retirement guidelines, while oil-fired capacity would be retired after operating at least five years beyond NEPOOL retirement guidelines (Exh. BP-1A at 3-23).

36 The Company stated that the requirements of the Federal Clean Air Act Amendments of 1990 ("CAAA"), including Phase II NOx limits which will become effective in 1999, are likely to impose significant costs on older fossil-fueled units (Exhs. BP-1A at 3-23; HO-RN-18). The Company also stated that the expense of emission control options will be compounded by the limited time over which incremental capital costs (continued...)

competitive generation market is likely to accelerate the retirement of existing NEPOOL units that are costly and inefficient (Tr. 6, at 68-71).

With respect to the HQ II transmission line, the Company explained that the availability of uncontracted power from Hydro Quebec, a winter peaking utility, is uncertain due to Hydro Quebec's own capacity needs and recent decisions to cancel or postpone a number of generating projects (Exh. BP-1A at 3-21 to 3-22). The Company indicated that NEPOOL may have overstated the capacity value of the unbooked HQ II transmission line, particularly in the winter, given that NEPOOL conducted its analysis of the capacity value of the transmission line prior to the cancellation of these projects (id.).

For the high supply scenario, the Company added capacity to the base supply scenario including: (1) the capacity of the Salem 3 unit (143 MW summer and winter); (2) all uncommitted portions of existing generation projects (190 MW summer, 211 MW winter); (3) 50 percent of the planned utility capacity additions classified as under licensing consideration in the 1995 CELT report (three MW increasing to 78 MW, summer and winter);[37] (4) 25 percent of the planned utility capacity additions classified as proposed in the 1995 CELT report (two MW increasing to 147 MW summer, two MW increasing to 224 MW winter); (5) 100 percent, instead of 75 percent, of the contracted capacity in NEES' Green RFP (an additional 10 MW summer and winter); and (6) 100 percent of the capacity of the Maine Yankee unit beginning in 1997 (an additional 87 MW summer, 88 MW winter) (Exhs. BP-RG-1, at 11-12; HO-RR-29; HO-RR-30).

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[36](...continued)
can be amortized given the age and limited remaining life of many of these units (Exh. HO-RN-18). The Company noted that other CAAA requirements regarding air toxics, fine particulates and further NOx requirements also may have a significant cost impact on these units in the 2000-2003 time-frame (Exh. BP-1A at 3-23).

[37] The Company indicated that the TEC project was included in this category, beginning in 2000, to reflect the project's current startup plans (Exhs. BP-RG-1, at 12; BP-1A at 3-27, n.17).

(2) Reserve Margin

The Company indicated that it incorporated reserve margins consistent with NEPOOL's current projections of required reserve margin (Exh. BP-1A at 3-28). The Company stated that, for the 1994 through 2000 period, it used the reserve margins from the September, 1994 NEPOOL document, "1994 Annual Review of NEPOOL Objective Capability and Associated Parameters" (id.). The Company added that, for the post-2000 period, summer and winter reserve margins were assumed to remain constant at their projected values for the year 2000 (id.).[38] Mr Graham indicated that reserve requirements are higher in the winter than in the summer because HQ II is a larger and more certain supply source in the summer (Tr. 6, at 80-81).

(B) Analysis

The Company has presented a base supply scenario based on the 1995 CELT report with adjustments for actual, planned and likely changes to NEPOOL supply, a low supply scenario based on possible losses of committed capacity included in the base supply scenario, and a high supply scenario based on possible implementation of additional supply options. The Company characterized the low supply scenario as the most likely forecast of supply, which the Siting Board should consider as the base case supply forecast.

As noted above, the Company's base supply scenario assumes the removal of the capacity of: (1) the Salem Harbor 1-3 units beginning in 1999; (2) uncommitted Enron and Great Bay capacity; and (3) recent NUG buyouts. In addition, the Company assumed that the Maine Yankee facility would be derated by ten percent over the forecast period. Here, the Siting Board considers the reasonableness of these assumptions.

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38 The Company assumed summer reserve margins as follows: (1) 1994, 22.0 percent; (2) 1995, 23.6 percent; (3) 1996, 22.7 percent; (4) 1997, 22.9 percent; (5) 1998, 22.7 percent; (6) 1999, 22.7 percent; (7) 2000 through 2008, 22.8 percent (Exh. BP-1A at 3-9). The Company assumed winter reserve margins as follows: (1) 1994/1995, 30.3 percent; (2) 1995/1996, 31.3 percent; (3) 1996/1997, 31.3 percent; (4) 1997/1998, 31.5 percent; (5) 1998/1999, 32.1 percent; (6) 1999/2000 through 2008/2009, 32.0 percent (id.).

With respect to the Salem Harbor 1-3 units, the Siting Board notes that, by 1999, these units will be operating beyond NEPOOL's retirement guidelines for coal-fired units. Although the Company provided copies of documents that were included in various regulatory proceedings to support its assertion that NEES will retire these units, the Siting Board is not persuaded that these documents are more current and accurate than NEPOOL's 1995 supply forecast. However, the Company has provided documentation that as of 1999, a number of other NEPOOL units also will be operating beyond NEPOOL's guidelines for retirement. It is therefore reasonable to conclude that the Salem Harbor units or an equivalent amount of capacity, operating beyond retirement guidelines, will be retired beginning in 1999, especially in light of CAAA requirements that are likely to take effect in 1999. Therefore, the Siting Board accepts the Company's assumption of the retirement of Salem Harbor 1-3 units in 1999.

With respect to the capacity of the uncommitted existing supply, the Siting Board notes that both the Enron unit and the Great Bay Project, as a portion of the Seabrook unit, are members of NEPOOL. The record demonstrates that the Enron unit is dispatched on the basis of its variable costs and availability and that the Great Bay Project is dispatched when the Seabrook unit is dispatched. Thus, even though neither the Enron unit nor the Great Bay Project have power sales agreements, and both are in effect competing with the proposed project to meet regional need, both the Enron unit and the Great Bay Project are currently available to supply peak demand in the region. Therefore, the Siting Board finds that the base case supply scenario should include the combined capacity of the Enron unit and the Great Bay Project totalling 190 MW, summer and 211 MW, winter.[39]

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39 The Siting Board recognizes that uncommitted existing supply has been excluded from the base case supply forecast in previous reviews of proposed facilities. See, e.g., Cabot Decision, 2 DOMSC at 284-286. However, the record demonstrates that in this case, all of the capacity considered to be uncommitted existing supply is owned by NEPOOL members and is dispatched as needed based on NEPOOL's operating guidelines.

With respect to the recent buyouts of NUG units, the Siting Board notes that all NUG units included in this category, with the exception of the FEV facility, are no longer operating. The Company suggested that after three years of continued operation, CMP likely will close the FEV unit due to its high costs. However, the record does not support a conclusion that the FEV unit will in fact be shut down. Accordingly, the Siting Board finds that the base supply scenario should include the capacity of the FEV unit, 32 MW summer and winter.

Finally, with respect to the assumption of the derating of the Maine Yankee unit by 10 percent over the forecast period, the Siting Board notes that documentation of the NRC's derating does not indicate if or when the unit will be allowed to operate at its full capacity. Therefore, for the purposes of this review, the Siting Board accepts the Company's assumption that the Maine Yankee unit will be derated by 10 percent over the forecast period.

As noted above, the Company asserted that the low supply scenario represents the most likely supply forecast, primarily because it reflects a realistic assessment of the continuing availability of older NEPOOL units and the capacity value of an unbooked HQ II transmission line. However, the Siting Board considers the retirement of the Salem Harbor 1-3 units, included in the base supply scenario, to be a reasonable representation of the potential retirement of capacity operating beyond NEPOOL retirement guidelines, particularly in the proposed on-line year and early life of the proposed project. Additional estimates of the retirement of existing capacity are appropriately reflected in the low case supply forecast. Further, the record in this case does not support a rejection of NEPOOL's most current assessment of the capacity value of an unbooked HQ II transmission line. An estimated reduction of the capacity of this line also is appropriate in the low case supply forecast.

Accordingly, the Siting Board finds that the Company's base supply scenario, as adjusted to include the capacity of the Enron unit, the Great Bay Project, and the FEV unit, represents an appropriate base case supply forecast for use in the analysis of regional need. In addition, the Siting Board finds that the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and, therefore, that the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need. The Siting Board further finds that the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and, therefore, that the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need.

Finally, with respect to reserve margins, the Company used NEPOOL's projected reserve margins for the years 1994 through 2000 and reasonably assumed that the reserve margins would remain at the projected values for the year 2000 in the years 2001 through 2008. Accordingly, the Siting Board finds that, for the purposes of this review, the reserve margins projected by the Company are appropriate.

iii. Need Forecasts

(A) Description

The Company developed 37 summer need forecasts (Exh. HO-RR-29). Thirty-six of the summer need forecasts were developed by adjusting each of four demand forecasts (1993 CELT forecast, 1994 initial CELT forecast, 1994 normalized CELT forecast, 1995 CELT forecast),[40] by each of three DSM scenarios, and comparing each of the resulting twelve adjusted demand forecasts with the three supply forecasts (id.). The remaining summer need forecast was based on a comparison of the 1994 normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast ("Company's base need scenario") (id.). Of these 37 summer need forecasts: (1) 30, or 81 percent, demonstrate a need for at least 252 MW of capacity in 1999; (2) 34, or 92 percent, demonstrate a need for at least 252 MW of capacity in 2000; and (3) 36, or 97 percent, demonstrate a need for at least 252 MW of

40 Because the 1994 final CELT forecast and the 1995 CELT forecast are identical in the long-run, the Company excluded the 1994 final CELT forecast from its count of need forecast scenarios (Exh. BP-RG-1, at 14, n.14).

capacity in 2001 (id.). See Table 1. The Company's base need scenario showed a need for 2,414 MW in 1999, with a greater need in subsequent years. See Table 1.

In addition, the Company developed 37 winter need forecasts for 1998/1999, including (1) 36 winter need forecasts based on a comparison of four demand forecasts (the 1993 CELT forecast, 1994 initial CELT forecast, 1994 final CELT forecast, and 1995 CELT forecast), each adjusted by three DSM scenarios, with the base, high and low supply forecasts, and (2) the Company's base need scenario (id.). For the years 1999/2000 and beyond, need forecasts based on the 1994 final CELT forecast were omitted since they were identical to those based on the 1995 CELT forecast (id.). Of the winter need forecasts: (1) 12, or 32 percent, demonstrate a need for at least 252 MW of capacity in 1998/1999; (2) 26 or 93 percent, demonstrate a need for at least 252 MW of capacity in 1999/2000; and (3) 28, or 100 percent, demonstrate a need for at least 252 MW of capacity in 2000/2001 (id.). See Table 2. The Company's base need scenario shows a need for 1,200 MW in 1998/1999, with greater need in subsequent years (id.). See Table 2.

(B) Analysis

In considering the Company's forecasts of summer peak load, the Siting Board has found that: (1) the 1994 initial CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond; (2) the 1995 CELT forecast is an appropriate low case summer peak load forecast for use in the analysis of regional need for the years 1999 and beyond; and (3) the 1994 normalized CELT forecast is a possible high case summer peak load forecast for use in an analysis of regional need for the years 1999 and beyond.

In considering the Company's forecasts of winter peak load, the Siting Board has found that the 1995 CELT forecast is an appropriate base case winter peak load forecast for use in the analysis of regional need for the years 1998/1999 and beyond.

In considering the Company's DSM forecasts, the Siting Board has found that: (1) NEPOOL's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis; and (3) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis.

In considering the Company's supply forecasts, Siting Board has found that: (1) the Company's base supply scenario, as adjusted to include the capacity of the Enron unit, the Great Bay Project, and the FEV unit, represents an appropriate base case supply forecast for use in the analysis of regional need; (2) the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and, therefore, that the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need; and (3) the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and, therefore, that the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need. In addition, the Siting Board has found that, for the purposes of this review, the reserve margins provided by the Company are appropriate.

While the Siting Board has accepted the 1995 CELT forecast of summer peak load and the 1994 normalized CELT forecast of summer peak load, the Siting Board has identified concerns with these forecasts. As a result of these concerns, the Siting Board places more weight on the base case forecast of summer peak load. Accordingly, the Siting Board here considers the need for the proposed project based on two compilations of the Company's need forecasts, as adjusted by the Siting Board, for summer peak load -- a compilation including only those need forecasts based on the 1994 initial CELT forecast, and an overall compilation of need forecasts based on all three summer peak load forecasts. The following table sets forth the number of summer need forecasts that demonstrate a need for at least 252 MW in the years 1999 through 2001.

Forecast	# Cases	1999	2000	2001
1994 Initial CELT	9	7 (78%)	9 (100%)	9 (100%)
All others	18	10 (56%)	14 (78%)	17 (94%)
Total	27	17 (63%)	23 (85%)	26 (96%)

The capacity positions under the summer need forecasts, as adjusted by the Siting Board, are shown in Table 3. Considered with the base case DSM forecast and the base case supply forecast, the first year that a need is demonstrated for at least 252 MW is: (1) 2000 for the 1994 initial CELT forecast (854 MW); (2) 2001 for the 1995 CELT forecast (352 MW); and (3) before 1999 for the 1994 normalized CELT forecast. See Table 3.

The Siting Board has accepted only one winter peak load forecast -- the 1995 CELT forecast of winter peak load. The number of winter need forecasts that demonstrate a need for at least 252 MW in each year, from 1998/1999 through 2000/2001, is as follows:

Forecast	# Cases	1998/1999	1999/2000	2000/2001
1995 CELT	9	1 (11%)	8 (89%)	9 (100%)

The capacity positions under the winter need forecasts, as adjusted are shown in Table 4. The first year of winter need for at least 252 MW under the 1995 CELT forecast, assuming the base case DSM forecast and base case supply forecast, is 1999/2000 (835 MW). See Table 4.

In sum, 17 of the 27 summer need forecasts, including seven of the nine need forecasts reflecting the base case demand forecast, show a need for at least 252 MW in 1999, while 23 summer need forecasts, including all of the need forecasts reflecting the base case demand forecast, show a need for at least 252 MW in 2000. In addition, eight of the nine winter need forecasts show a need for at least 252 MW in 1999/2000.

Accordingly, based on the foregoing, the Siting Board finds a likely need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 1999, and a clear need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

b. Massachusetts

BPD asserted that there is a need for new capacity in Massachusetts by the year 1999 or earlier (Company Brief at 54). To support its assertions, BPD presented a series of forecasts of demand and supply for Massachusetts, based primarily on the 1993, 1994 and 1995 forecast documents and other data published by NEPOOL, and, as necessary, prorated to Massachusetts by the Company (Exhs. BP-1A at 3-31 to 3-42; HO-RR-45). The Company stated that it then compared its demand and supply forecasts to produce a series of need forecasts (Exh. BP-RG-1, at 18).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including its demand forecast methods and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including its capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts.

i. Demand Forecasts

(A) Description

In developing load forecasts for Massachusetts, BPD indicated that it relied primarily on NEPOOL Massachusetts-specific forecasts of adjusted peak load which correspond to the regional CELT Report forecasts of adjusted load (Exh. BP-1A at 3-32).[41] The Company presented five forecasts of Massachusetts unadjusted summer peak load and five forecasts of Massachusetts unadjusted winter peak load (id. at 3-32, 3-33; Exhs. BP-RG-1, at 16-17; HO-RR-45). BPD stated that it added the NEPOOL reference Massachusetts DSM forecast

41 BPD stated that NEPOOL prepares individual state forecasts by allocating the regional forecast to the individual states (Tr. 8, at 65-66). BPD also stated that NEPOOL's individual state forecasts include the effects of NUG-netted-from-load and Company-sponsored DSM (Exh. BP-1A at 3-32, n.20).

for each year to the adjusted load forecasts in order to produce Massachusetts unadjusted load forecasts consistent with its regional load forecasts (Exh. BP-1A at 3-33). BPD further stated that, in order to prepare forecasts of adjusted load, it combined these forecasts with three forecasts of DSM savings based on NEPOOL's most current forecast of Massachusetts-specific DSM savings. Overall, the Company provided thirteen forecasts of Massachusetts adjusted summer peak load and thirteen forecasts of Massachusetts adjusted winter peak load (Exh. HO-RR-45).

(1) Demand Forecast Methods

The Company indicated that it developed forecasts of Massachusetts peak load corresponding to each of the demand forecasts presented in the regional need analysis, with the exception of the 1994 normalized CELT forecast (id.; Exhs. BP-1A at 3-32, 3-33; BP-RG-1, at 16-17).[42] The Company stated that the forecasts corresponding to the 1993 CELT forecast ("1993 NEPOOL Massachusetts forecast") and 1994 final CELT forecast ("1994 final NEPOOL Massachusetts forecast") were based directly on NEPOOL forecasts of Massachusetts summer and winter peak load for 1993 and 1994 respectively, which were included in the NEPOOL report, "Energy and Peak Load Forecast Exhibits, Massachusetts," for 1993 and 1994 (Exh. BP-1A at 3-32 to 3-33).[43]

The Company indicated that NEPOOL did not prepare a Massachusetts-specific forecast in conjunction with either the 1994 initial CELT report or the 1995 CELT report (id.; Exh. BP-RG-1, at 16). The Company stated that it developed Massachusetts summer and winter peak forecasts corresponding to the 1994 initial CELT forecast ("1994 initial

42 The Company stated that a Massachusetts forecast corresponding to the 1994 normalized forecast was not developed because data for the Massachusetts 1994 weather-normalized summer peak load was not available (Exh. BP-1A at 3-33, n.21).

43 Mr. Graham reported that NEPOOL's forecasts of coincident peak were utilized rather than the forecasts of "own-state" load (Exh. BP-RG-1, at 16, n.5). He noted that the coincident peak forecasts were equal to or slightly lower than the "own-state" forecast for all years (id.).

NEPOOL Massachusetts forecast") and 1995 CELT forecast ("1995 NEPOOL Massachusetts forecast") by prorating the 1994 final NEPOOL Massachusetts forecast (Exhs. BP-1A at 3-34; BP-RG-1, at 16). To develop the 1994 initial NEPOOL Massachusetts forecast, the Company multiplied the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1994 initial CELT forecast to the 1994 final CELT forecast (Exh. BP-1A at 3-34). To develop the 1995 NEPOOL Massachusetts forecast, the Company multiplied the 1994 final NEPOOL Massachusetts forecast by the ratio of the 1995 CELT forecast to the 1994 final CELT forecast (Exh. BP-RD-1, at 16).[44] The Company noted that, like the corresponding regional forecasts, the 1994 final NEPOOL Massachusetts forecast and the 1995 NEPOOL Massachusetts forecast are identical in the years 1999 and beyond (Exh. BP-RG-1, at 16, n.6). In addition, the Company developed summer and winter peak load forecasts corresponding to the 1994 normalized 2.5 percent forecast ("1994 Massachusetts normalized 2.5 percent forecast") (Exh. HO-RR-45).[45]

Consistent with the regional need analysis, the Company asserted that the 1994 Massachusetts normalized 2.5 percent forecast was the most likely forecast of demand (Company Brief at 55). In addition, BPD stated that the concerns it raised relative to the various regional need forecasts also would apply to the corresponding Massachusetts need forecasts (Tr. 8, at 66).

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44 BPD asserted that the ratio used to develop the 1995 NEPOOL Massachusetts forecast is conservative in that it assumes that Massachusetts will receive a prorated share of any increase in demand exhibited in the 1995 CELT forecast relative to the 1994 final CELT forecast, even though the Massachusetts economy has improved more than the New England economy as a whole (Exh. BP-RG-1, at 17).

45 The Company also provided a second 1994 Massachusetts normalized 2.5 percent forecast for Massachusetts using NEPOOL's reported peak as a starting point (Exh. HO-RR-45). For the reasons noted in Section II.A.2.a.i, above, the Siting Board does not consider the second 1994 Massachusetts normalized 2.5 percent in its review of Massachusetts need.

(2) DSM

The Company provided three forecasts of Massachusetts DSM: (1) a base Massachusetts DSM scenario taken directly from the 1994 report, "NEPOOL Participant Planned Demand-Side Management Impacts on the NEPOOL Forecast, 1994-2009," which is NEPOOL's most recent state-by-state forecast of DSM savings; (2) a high Massachusetts DSM scenario which assumes that the post-1994 DSM growth rate is ten percent higher than the base Massachusetts DSM scenario; and (3) a low Massachusetts DSM scenario which assumes that the post-1994 DSM growth rate is 25 percent lower than the base Massachusetts DSM scenario (Exh. BP-1A at 3-33 to 3-34). Consistent with its regional need analysis, the Company asserted that the low Massachusetts DSM scenario was the most likely forecast of future DSM savings (Exh. HO-RR-45).

(B) Analysis

BPD has provided five demand forecasts for its Massachusetts need analysis which correspond to the demand forecasts presented in its regional need analysis. The Siting Board reviewed the regional demand forecasts in Section II.A.2.a.i, above.

For the reasons set forth in Section II.A.2.a.i.(B), above, the Siting Board will rely on the more recent CELT-based forecasts instead of the 1993 NEPOOL Massachusetts forecast in its analysis of Massachusetts demand in this proceeding.

Consistent with its findings concerning the remaining regional demand forecasts, the Siting Board finds that: (1) the 1994 initial NEPOOL Massachusetts forecast is an appropriate base case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; (2) the 1995 NEPOOL Massachusetts forecast is an appropriate low case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; and (3) the 1995 NEPOOL Massachusetts forecast is an appropriate base case winter peak load forecast for use in the analysis of Massachusetts need for the years 1998/1999 and beyond.[46]

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.i, above.

Consistent with its findings concerning the regional forecasts of DSM savings, the Siting Board finds that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

ii. Supply Forecasts

(A) Description

(1) Capacity Assumptions

The Company stated that it developed base, high and low supply scenarios for Massachusetts which are consistent with the Company's regional supply scenarios (Exhs. BP-1A at 3-35 to 3-40; BP-RG-1, at 17). The Company stated that its base Massachusetts supply scenario reflects the committed capacity that (1) is owned or contracted by Massachusetts utilities, regardless of location, and (2) was included in the 1995 CELT Report (Exhs. BP-1A at 3-35 to 3-36; BP-RG-1, at 17). The Company indicated that for utilities with sales in more than one state, supplies were prorated based on the average ratio

46 The Company did not submit a Massachusetts forecast similar to the 1994 normalized CELT forecast.

of each utility's projected Massachusetts summer peak demand to its total system projected peak demand over the forecast period (Exh. BP-1A at 3-37).[47]

The Company stated that it adjusted the Massachusetts-specific information from the 1995 NEPOOL supply forecast to reflect current information on actual and planned changes to 1995 NEPOOL supply and such adjustments were consistent with its adjustments in the regional base case supply scenario (id.). The Company noted that each such adjustment was analyzed on a utility-by-utility basis in order to make the appropriate allocation to Massachusetts (id. at 3-37 to 3-38). In Section II.A.2.a.ii.(B), above, the Siting Board found that the regional base case supply scenario should include the combined capacity of the Enron unit and the Great Bay Project. The Company has indicated that Massachusetts' share of the combined capacity of the Enron unit and the Great Bay Project is 138.8 MW summer and 148.2 MW winter (Exh. BP-RG-1, exh. 22).[48]

The Company stated that its Massachusetts low case supply scenario is comparable to the regional low case supply scenario (id. at 17). The Company noted that all reductions to the base case supply scenario assumed in the low case supply scenario were prorated to reflect Massachusetts utilities' share of the capacity (Exh. BP-1A at 3-39). In addition, the Company stated that its Massachusetts high case supply scenario also is comparable to the regional high case supply scenario (id.). In allocating supply increases to Massachusetts, the Company indicated that where existing or proposed facilities (1) could be associated with a specific utility, capacity was allocated to that utility, and (2) could not be associated with a

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47 The Company stated that NEES, Eastern Edison Company ("Eastern Edison"), WMECo, and Massachusetts Municipal Wholesale Electric Company ("MMWEC") make out-of-state sales (Exh. BP-1A at 3-37). The Company indicated that its prorating ratio for MMWEC was determined based on the proportion of its annual sales to out-of-state entities because peak demand was not available (id.).

48 In Section II.A.2.a.ii.(B), above, the Siting Board found that the base case supply scenario also should include the capacity of the FEV unit, 32 MW summer and winter. However, because this unit is owned by CMP, none of its capacity is allocable to Massachusetts utilities.

specific utility, capacity was allocated to Massachusetts based on the average ratio of Massachusetts to NEPOOL peak load over the forecast period (id. at 3-40).

Consistent with the regional need analysis, the Company asserted that the low case supply scenario was the most likely forecast of Massachusetts supply (Exh. HO-RR-45).

(2) Reserve Margins

BPD stated that it assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region (Exh. BP-1A at 3-40 to 3-41). Thus, as noted in Section, II.A.2.a.ii.(A)(2), above, BPD utilized NEPOOL reserve margins for the years 1994 through 2000 and assumed that reserve margins would remain constant at their year 2000 levels for the remainder of the forecast period.

(B) Analysis

The Company provided a base case, low case and high case supply scenario for Massachusetts, corresponding to the supply forecasts presented in its regional need analysis. The Siting Board reviewed those forecasts in Section II.A.2.a.ii, above.

Consistent with its findings relative to the regional need analysis, the Siting Board finds that: (1) the Company's base case supply scenario, as adjusted to include the proportionate capacity of the Enron unit and the Great Bay Project, represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need.

In addition, the Company assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region. Consistent with its finding relative to the regional need analysis, the Siting Board finds that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

iii. Need Forecasts

(A) Description

The Company developed 28 summer need forecasts for Massachusetts (Exh. HO-RR-45). Twenty-seven of these were developed by adjusting each of three demand forecasts (the 1993 NEPOOL Massachusetts forecast, 1994 initial NEPOOL Massachusetts forecast, and 1995 NEPOOL Massachusetts forecast),[49] by each of the three DSM scenarios and comparing each of the nine resulting adjusted demand forecasts with the three supply forecasts (id.). The remaining summer need forecast was based on a comparison of the 1994 Massachusetts normalized 2.5 percent forecast, adjusted by the low DSM scenario, with the low supply forecast ("Company's Massachusetts base need scenario") (id.). All of the Company's summer need scenarios demonstrated a need for 252 MW by 1999 (id.). See Table 5.

In addition, the Company developed 37 winter need forecasts for 1998/1999 including (1) 36 winter need forecasts based on a comparison of four demand forecasts (the 1993 NEPOOL Massachusetts forecast, 1994 initial NEPOOL Massachusetts forecast, 1995 NEPOOL Massachusetts forecast, and 1994 final NEPOOL Massachusetts forecast), each adjusted by base, high, and low DSM scenarios, with the base, high, and low supply forecasts, and (2) the Company's Massachusetts base need scenario. For the years 1999/2000 and beyond, need forecasts based on the 1994 final NEPOOL Massachusetts forecast were omitted, resulting in a total of 28 need forecasts for those years. None of the Company's winter need forecast scenarios show a need for at least 252 MW of capacity in the year 1998/1999. Fourteen need forecast scenarios, or 50 percent, show a need for at least 252 MW of capacity in 1999/2000, while 28 need forecast scenarios, or 100 percent, show a need for at least 252 MW in 2000/2001. See Table 6. The Company's Massachusetts base need scenario showed a need for: (1) 21 MW in 1998/1999; (2) 586 MW in 1999/2000; and (3) 851 MW in 2000/2001. See Table 6.

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49 The Company excluded the 1994 final NEPOOL Massachusetts forecast because it duplicates the 1995 NEPOOL Massachusetts forecast (Exh. HO-RR-45(att. j)).

(B) Analysis

Consistent with the regional need analysis, the Siting Board finds that it is appropriate to explicitly consider Massachusetts need for the proposed facility within the 1998/1999 to 2002 time frame.

The Siting Board has found that: (1) the 1994 initial NEPOOL Massachusetts forecast is an appropriate base case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; (2) the 1995 NEPOOL Massachusetts forecast is an appropriate low case summer peak load forecast for use in the analysis of Massachusetts need for the years 1999 and beyond; and (3) the 1995 NEPOOL Massachusetts forecast is an appropriate base case winter peak load forecast for use in the analysis of Massachusetts need for the years 1998/1999 and beyond.

In considering the Company's DSM forecasts, the Siting Board has found that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base case supply scenario, as adjusted to include the proportionate capacity of the Enron unit and the Great Bay Project, represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need. In addition, the Siting Board has found that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

The Siting Board's concerns regarding the 1995 CELT forecast extend to the 1995 Massachusetts NEPOOL forecast of summer peak load. These concerns affect the weight the Siting Board places on this forecast. Consequently, the Siting Board places more weight on the base case forecast -- the 1994 initial NEPOOL Massachusetts forecast. However, as noted above, all Massachusetts summer need forecasts, including those that incorporate the base case supply scenario as adjusted above, show a need for at least 252 MW in 1999. See Table 7. Accordingly, based on the foregoing, the Siting Board finds need for 252 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1999 and beyond.[50]

3. Economic Need

a. New England

i. Description

The Company asserted that there is a need for the proposed facility on economic efficiency grounds (Company Brief at 46). The Company maintained that the proposed facility would provide economic efficiency benefits to the region both under the existing NEPOOL dispatch system and under a modified dispatch system consistent with anticipated electric industry restructuring (id. at 46, 49-51).

In support of its assertions with respect to the existing NEPOOL dispatch system, BPD provided a series of detailed economic analyses based on existing NEPOOL dispatch practices[51] for the 20-year period, 1999 through 2018, which compared the total incremental variable costs of two scenarios -- one that included the dispatch of the proposed facility ("Berkshire-in case") and one without the proposed facility ("Berkshire-out case") (Exhs. BP-1A(att. 3-31); HO-RN-35; HO-RR-44(red.)). The Company stated that these

50 The Siting Board notes that Massachusetts winter need forecasts demonstrate a later year of need than the Massachusetts summer need forecasts. See Table 8.

51 Mr. Graham stated that the current NEPOOL dispatch order is based on the variable costs (i.e., variable fuel costs and variable operation and maintenance ("O&M") costs) of NEPOOL units (Tr. 7, at 97). He stated that the units with the least expensive variable costs are dispatched first, with the exception of must-run units (those units which have to be run for contractual, transmission, or other reasons) which are dispatched whenever they are available (id.).

analyses demonstrate that the proposed facility would provide significant, assured economic efficiency benefits to the region that would be equal to the difference in the region's cost of electricity under these two scenarios (Exh. BP-1A at 3-43 to 3-44). The Company stated that such economic efficiency benefits would accrue to the region due to (1) the displacement by the proposed project of more expensive power sources in NEPOOL's dispatch order, and (2) differences in incremental fixed cost requirements in the Berkshire-in case relative to the Berkshire-out case (id.).

The Company stated that it used the ENPRO model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 3-44).[52] The Company indicated that inputs into the ENPRO model included: (1) a load duration curve;[53] (2) load growth scenarios; (3) plant specific information for existing units;[54] (4) escalation factors for

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52 The Company indicated that the ENPRO model simulates the dispatch of all NEPOOL power plants on an hourly basis, taking into account changes in NEPOOL load, unit additions and retirements, changes in unit dispatch costs and resulting changes to the NEPOOL system dispatch (Exh. BP-1A at 3-44).

53 BPD indicated that it used NEPOOL's actual 1991 hourly loads as a base year and assumed that the hourly load shape and system load factor would remain constant over the forecast period (Exh. BP-1A at 3-46). BPD asserted that this was a conservative assumption, given that NEPOOL is projecting a small increase in its load factor over time (Exh. HO-RN-25). The Company explained that a higher load factor would require older, more expensive and more polluting units to operate at a higher capacity factor than assumed in the analyses, and that the energy displaced by the proposed project under a higher load factor scenario would be higher in cost and more polluting (id.).

54 The Company stated that the plant-specific information for each existing unit included generating capacity, fuel type(s), fuel costs, variable non-fuel costs, average heat rate, unit availability, emissions data, must-run status, and other operating characteristics (Exh. BP-1A at 3-45). BPD stated that this information was obtained primarily from FERC Form 1 filings, utility performance filings with the Department of Public Utilities ("Department"), NEPOOL NX-12 forms, and the 1994 NEPOOL Generation Task Force report ("1994 GTF") (id.). BPD indicated that average heat rate and unit availability were assumed to remain constant over the forecast period (Exh. HO-RN-28). BPD also indicated that existing gas/oil dual fuel units were assumed to burn gas for nine months of the year (Exh. HO-RN-27).

current dispatch prices;[55] (5) scheduled and projected plant retirements and additions[56] including the addition of new generic capacity to meet projected regional capacity requirements; (6) classification of specific units as must-run units;[57] and (7) operating characteristics and dispatch price for the proposed facility (id. at 3-44 to 3-49).

With respect to load growth scenarios, the Company stated that hourly loads were adjusted over the forecast period based on two different load growth scenarios for unadjusted peak -- the 1993 CELT forecast and the 1994 final CELT forecast[58] -- each paired with the base DSM scenario and a base supply forecast derived from the 1994 final CELT report (Exh. BP-1A at 3-46).[59]

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[55] The Company stated that base-year plant dispatch prices were based on actual NEPOOL dispatch price data obtained from the NEPOOL Monthly Fuel Summary for 1994 (Exh. BP-1A at 3-45 to 3-46). The Company also stated that actual 1994 base year dispatch prices, of which fuel and variable O&M are the largest part, were escalated based on the 1994 GTF (Exhs. HO-RN-27; HO-A-8).

[56] The Company stated that plant retirement assumptions are consistent with the base case supply scenario (Exh. HO-RR-29).

[57] BPD classified all of NEPOOL's conventional hydropower, baseload external purchases, portions of certain existing fossil units, and certain purchases from existing and committed NUGs as must-run (Exh. BP-1A at 3-44). BPD stated that its list of must-run capacity reflects its understanding of NEPOOL's must-run capacity (Exh. HO-RN-24).

[58] The Company indicated that these two load growth scenarios were selected because they represent the highest and lowest load growth forecasts in the regional need analysis and, as such, provide reasonable upper and lower bounds for the magnitude of cost savings over time (Exh. BP-1A at 3-46).

[59] The Company did not update its dispatch analysis based on the 1995 CELT report (Exh. BP-RG-1, at 19). As noted in Section II.A.2.a.i.(A)(1), above, the Company stated the 1995 CELT forecast and 1994 final CELT forecasts are identical beginning in the year 1999. The Company stated that, although there were several changes in supply in the 1995 CELT report relative to the 1994 final CELT report, such changes were relatively small and would not have a significant impact on the results of the analyses (id.).

In its analysis, BPD assumed three types of new generic capacity: (1) 225 MW gas-fired combined cycle ("GTCC") units; (2) 500 MW integrated coal gasification combined cycle ("IGCC") units; and (3) 80 MW oil-fired combustion turbines for peaking capacity (id. at 3-47).[60] BPD stated that the type and timing of the generic capacity additions were based on an optimal NEPOOL generation mix (id.).[61] BPD assumed that the performance characteristics of the new generic capacity would remain unchanged over the forecast period (Tr. 8, at 29-30). BPD also assumed that the GTCC units would be less efficient than the proposed project over the forecast period and therefore that the proposed facility would be dispatched ahead of the GTCC units (id., at 30).[62]

With respect to the costs and operating characteristics of the proposed facility, the Company provided analyses based on two differing assumptions for heat rate -- (1) an originally assumed approximate heat rate of 7,000 British thermal units per kilowatt hour

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60 BPD stated that the cost and performance characteristics of the generic units were obtained from the 1993 Electric Power Research Institute ("EPRI") Technical Assessment Guide ("TAG") Report ("1993 TAG") (Exh. BP-1A at 3-48). BPD further stated that initial fuel prices and escalators were obtained from the 1994 GTF (id.). The Company noted that costs, performance characteristics and fuel prices of the GTCC and IGCC units were consistent with those used in the technology alternatives analysis (id. at 3-47 to 3-48).

61 The Company stated that NEPOOL's total cost would be minimized over time with 45 percent baseload capacity, 40 percent cycling capacity and 15 percent peaking capacity (Exh. HO-RN-26). The Company noted that, in adding generic capacity, all of the IGCC units and 30 percent of the GTCC units were designated as baseload capacity, and the remaining 70 percent of the GTCC units were designated as cycling capacity (id.).

62 Mr. Graham stated that the proposed project has a fairly significant heat rate advantage over the GTCC units in the analysis and that significant technology improvements would have to be assumed for the generic units to reach the efficiency level of the proposed facility (Tr. 8, at 30). He added that some improvement in technology would lead to improved efficiency in the generic units over time but would not affect the analysis in the short term (id.).

("Btu/kwh") ("higher heat rate"), and (2) an updated heat rate[63] ("lower heat rate") (Exhs. BP-1A at 3-31; HO-RN-35; HO-RN-44). BPD indicated that its analyses assume a fuel cost based on a firm gas supply from the wellhead to the proposed facility ("firm gas supply") (Tr. 7, at 101-103). BPD indicated that a firm gas supply, which would have a high demand charge and low variable cost, would be an appropriate supply given NEPOOL's current dispatch practices, which are based on variable cost (id.). However, the Company stated that it actually anticipates contracting for firm transportation only from Wright, New York to the project ("Wright gas supply"), an arrangement which would have a higher variable cost and lower total cost than a firm gas supply (id. at 98-99, 102). The Company explained that the Wright gas supply would be advantageous if NEPOOL dispatch practices change as a result of electric industry restructuring so that dispatch would be based on total cost (id. at 102).[64]

The Company stated that the ENPRO model provided the NEPOOL system variable dispatch costs associated with each set of assumptions (Exh. BP-1A at 3-47). In order to assess total cost savings, the Company stated that variable dispatch costs were added to the incremental capital costs of the proposed facility[65] and generic units for each case to produce total costs (id. at 3-48). The Company stated that the NEPOOL system-wide savings attributable to the proposed facility would be the difference in total costs between the Berkshire-in case and Berkshire-out case (id. at 3-48 to 3-49). The Company stated that the

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63 Pursuant to Siting Board regulations, the Company has requested that the updated heat rate be considered proprietary and be afforded confidential treatment.

64 The Company also stated that use of the Wright fuel supply under existing NEPOOL dispatch practices would cause the proposed project to drop in the dispatch order (Exh. HO-RR-39(red.)). However, BPD asserted that the proposed facility would nearly always be dispatched when available because its capacity factor would continue to be almost equal to its availability rating (id.).

65 BPD stated that capital costs of the proposed facility were obtained from the financial pro-forma of the project (Exh. BP-1A at 3-47).

annual nominal savings were discounted to 1995 dollars to obtain the net present value ("NPV") of economic efficiency savings attributable to the proposed project (id. at 3-49).[66]

The Company provided Berkshire-out and Berkshire-in cases for the years 1999 through 2018, for the following scenarios: (1) 1993 CELT forecast, higher heat rate and firm gas supply ("1993 CELT dispatch scenario"); (2) 1994 final CELT forecast, higher heat rate and firm gas supply ("1994 CELT dispatch scenario"); and (3) 1994 final CELT forecast, lower heat rate and firm gas supply ("updated 1994 CELT dispatch scenario") (Exhs. HO-RN-35; HO-RR-44(red.)).[67]

The Company indicated that under the 1993 CELT dispatch scenario (1) there would be a positive annual net economic benefit to the region in each year of the forecast period, and (2) the proposed project would result in $295.9 million NPV of savings in 1995 dollars over the 20-year forecast period (Exh. BP-1A at 3-49, att. 3-31).[68]

BPD indicated that, under the 1994 CELT dispatch and the updated 1994 CELT dispatch scenarios, there would be a positive annual net economic benefit to the region in all years of the forecast period with the exception of 1999, when the proposed project would increase total costs (id. at att. 3-31; HO-RR-44(red.)).[69] The Company noted that the

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66 BPD indicated that annual nominal savings were discounted to 1995 dollars using the weighted average cost of capital (ten percent) in the 1994 GTF (Exh. BP-1A at 3-49).

67 The updated 1994 CELT dispatch scenario also corrects for an error in the timing of the addition of the first two generic GTCC units in the 1994 CELT dispatch scenario Berkshire-out case (Exh. HO-RR-44(red.)).

68 The Company indicated that the NPV of the total economic efficiency savings, discounted by ten percent to 1999 dollars would be $328.50 million (Exh. BP-1A at att. 3-31). The Company also indicated that, savings in 1995 dollars, for the first five years of the operation of the proposed project would be: (1) $35.10 million in 1999; (2) $37.85 million in 2000; (3) $16.79 million in 2001; (4) $37.85 million in 2002; and (5) $20.30 million in 2003 (id.).

69 The Company indicated that total costs would increase by $24.23 million under the 1994 CELT dispatch scenario and $23.10 million under the updated 1994 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)).

Berkshire-in case assumes that 100 percent of the proposed project is sold in 1999 even though there is no identified capacity need until 2000 (Exh. HO-RN-32).[70] In addition, the Company stated that, over the forecast period, the NPV in savings in 1995 dollars provided by the proposed project would be (1) $241.7 million under the 1994 CELT dispatch scenario, and (2) $248.6 million under the updated 1994 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)).[71] The Company also indicated that the NPV of savings in the first five years of facility operation, in 1995 dollars, would be (1) $57.15 million, or 23 percent of the total savings, under the updated 1994 CELT dispatch scenario, and (2) $113.2 million, or 38 percent of the total savings, under the 1993 CELT dispatch scenario (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)). The Company expressed a high degree of confidence in the analysis in the short-term, but stated that there was more uncertainty in the projected savings as the forecast extended over the long-term (Tr. 8, at 33-34).

The Company asserted that the cost savings attributable to the proposed facility are likely to be even greater under electric industry restructuring than they are under existing NEPOOL dispatch (Company Brief at 49-50). The Company stated that, with electric industry restructuring, regional dispatch likely would change to a bidding system, and that total plant costs, not just variable costs, would be reflected in a facility's bid (id. at 49; Tr. 7, at 101-102). As will be discussed in Section II.C.2.a, below, the Company asserted that the total costs of the proposed facility are below the operating costs of many existing

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70 The Company also noted that although the proposed project provides savings in dispatch costs in 1999, these savings are not enough to compensate for the fixed capacity charges of the proposed project (Exh. HO-RN-32).

71 The Company indicated that, under the updated 1994 CELT dispatch scenario, the NPV of the total economic efficiency savings, discounted by ten percent to 1999 dollars, would be $276 million (Exh. HO-RR-44(red.)). The Company also indicated that, under the updated 1994 CELT dispatch scenario, total costs would increase in 1999 by $23.1 million in 1999 dollars and that savings in current year dollars for the next four years of the operation of the proposed project would be: (1) $40.79 million in 2000; (2) $18.95 million in 2001; (3) $23.5 million in 2002; and (4) $23.65 million in 2003 (id.).

generating units. Therefore, the Company argued that the proposed facility likely would be dispatched more often under a total cost dispatch system than under the current dispatch system and would displace greater amounts of more expensive generation (Company Brief at 50, citing, Exhs. HO-RN-39; HO-V-21; BP-RG-32; Tr. 8, at 46-56).

ii. Position of the Parties

CCBA asserted that the Company had "dispensed tremendous misinformation surrounding the need for the proposed power plant and the alleged benefit to electric rate payers" (CCBA Brief at 1). CCBA also argued that there is no need for the proposed project, "based on extensive research" (id.). In response, BPD argued that the failure of CCBA to support its position with record information evidences CCBA's inability to refute the evidence in the record that demonstrates need for the proposed project (Company Reply Brief at 1).[72]

iii. Analysis

In the past, the Siting Board has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1995 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and in Boston Gas Company, 11 DOMSC 159, 166-168 (1984), the Siting Board 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 indicates that need may be established on either reliability, economic, or

72 BPD also took issue with CCBA's reference to "facts" that were not a part of the official administrative record in this proceeding, and urged the Siting Board to strike those portions of CCBA's brief which relied on such facts or, in the alternative, to "only accord [those portions] the appropriate amount of weight" that they are due (id. at 1, 2).

environmental grounds. Cabot Decision, 2 DOMSB at 296-300; Altresco Lynn Decision, 2 DOMSB at 22-27; 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. Cabot Decision, 2 DOMSB at 292-296; Altresco Lynn Decision, 2 DOMSB at 61-65; MASSPOWER Decision, 20 DOMSC at 19.

In some cases, the Siting Board rejected companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Board noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds. See Eastern Energy Corporation, 22 DOMSC 188 210-211 (1991) ("EEC Decision"); West Lynn Decision, 22 DOMSC at 14; MASSPOWER Decision, 20 DOMSC at 19.

In more recent reviews of non-utility proposals, the Siting Board has found that the proposed projects were needed for economic efficiency purposes. See Altresco Lynn Decision, 2 DOMSB at 68; Enron Decision, 23 DOMSC at 55-62. The Siting Board has noted that such findings, based on a comprehensive analysis of NEPOOL dispatch, both with and without each proposed project, are necessarily project-specific. In addition, the Siting Board has indicated that, since regional economic efficiency gains are not contractually guaranteed, unlike economic efficiency gains associated with specific PPA's, the degree to which such regional gains are assured would be a critical factor in its evaluation of regional need for economic efficiency purposes. The Siting Board also has identified the magnitude and timing of such gains as critical to its review.

Here, the Company has provided a detailed description of the methods and assumptions used in its analysis of economic efficiency savings. BPD's use of two load growth forecasts in developing dispatch scenarios allows the Siting Board to evaluate the degree to which economic efficiency savings are assured, given uncertainties in future load growth.[73]

Although the Company's analysis recognizes uncertainties in future load growth, it does not account for future uncertainty in fuel price forecasts. A range of fuel price forecasts would have strengthened this analysis, particularly since (1) there is no fuel contract for the proposed facility, and (2) the fuel supply assumed for the analysis is not that anticipated for the proposed facility.

In addition, while the Company's analyses are generally based on reasonable assumptions, certain assumptions are questionable over a 20-year period. For instance, the Company assumes that the proposed project will have a significantly lower heat rate than the generic GTCC units throughout the 1999-2018 time period and that the fuel mix for the dual fuel oil/gas units will remain consistent at nine months gas/three months oil.

Nevertheless, the analyses provided by the Company indicate that under both the 1993 CELT dispatch scenario and updated 1994 CELT dispatch scenario, the proposed project would provide substantial economic efficiency savings over the 20-year period from 1999 to 2018. The NPV of savings, in 1995 dollars, over the 20-year period would range from \$248.58 million under the updated 1994 CELT dispatch scenario to \$295.87 million under the 1993 CELT dispatch scenario. The Siting Board agrees with the Company that there is more confidence in the dispatch analysis in the short-term, and notes that the NPV of savings for the first five years of the proposed project, in 1995 dollars, would be (1) \$57.15 million, or 23 percent of the total savings, under the updated 1994 CELT dispatch scenario, and (2) \$113.2 million, or 38 percent of the total savings, under the 1993 CELT dispatch scenario.[74] Thus, BPD has established that New England would recognize economic

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[73] The Siting Board does not further consider the 1994 CELT dispatch scenario.

[74] The Siting Board notes that the ratio of NPV in 1995 dollars to NPV in 1999 dollars is 90.067 percent (Exhs. BP-1A at att. 3-31; HO-RR-44(red.)). To obtain the NPV, in 1995 dollars for the first five years of each dispatch analysis, the annual economic efficiency savings (or costs) were discounted by ten percent per year to 1999 and then multiplied by 90.067 percent.

savings of a substantial magnitude from the operation of the proposed project during its first five years of operation under a range of demand forecasts.

Under each of the dispatch analyses, the first year of economic efficiency savings is coincident with the first year of capacity need. Thus, economic efficiency savings would begin to accrue in 1999 under the 1993 CELT dispatch scenario and in 2000 under the updated 1994 final CELT dispatch scenario.

Accordingly, the Siting Board finds that BPD has established that there will be a need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the first year of capacity need in New England. Further, consistent with its findings regarding reliability need in New England, the Siting Board finds that there will be a likely need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 1999 and that, there will be a clear need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000.

b. Massachusetts

The Company asserted that Massachusetts will require the capacity represented by the proposed facility for economic efficiency purposes (Company Brief at 56). The Company stated that economic efficiency benefits will accrue to direct purchasers of electricity from the proposed facility and to NEPOOL as a whole, because system-wide costs would be lower with the operation of the proposed facility than without operation of the proposed facility (Exh. HO-RN-38, at 1). The Company further stated that, because the purchasers of electricity from the proposed facility are not known and may change over time, it is reasonable to assume that regional economic efficiency benefits would accrue to Massachusetts in proportion to Massachusetts' energy consumption (id.). BPD noted that, over the 1999 to 2009 period, NEPOOL calculates that Massachusetts will account for approximately 44.5 percent of NEPOOL's annual "net energy for load"[75] (id. at 1, and att. a). The Company stated that Massachusetts customers should realize a similar percentage of the economic efficiency benefits provided by operation of the proposed facility (id. at 1).[76]

In Section II.A.3.a.ii, above, the Siting Board determined that New England would recognize economic savings of a substantial magnitude from the operation of the proposed project during its first five years of operation under a range of demand forecasts. In addition, the Siting Board found that there would be a need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the first year of capacity need in New England.

Although the record in this case does not support a finding regarding the extent of savings that would accrue to Massachusetts, it is clear that Massachusetts will share in the regional economic efficiency benefits provided by the operation of the proposed facility, once those benefits begin. Accordingly, the Siting Board finds that there is a need in Massachusetts for the additional energy resources produced by the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region.

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75 The Company explained that net energy for load represents projected electricity consumption, including sales and losses (Exh. HO-RN-38).

76 The Company's analysis indicates that operation of the proposed facility would provide Massachusetts with NPV savings in 1995 dollars ranging from (1) $110.62 million under the updated 1994 CELT dispatch scenario to $131.66 million under the 1993 CELT dispatch scenario, over the 20-year period from 1999 to 2018, and (2) $25.43 million under the updated 1994 CELT dispatch scenario to $50.38 million under the 1993 CELT dispatch scenario, over the five-year period from 1999 to 2003 (Exhs. HO-RN-38; BP-1A at att. 3-31; HO-RR-44(red.)).

4. Environmental Need

a. Description

BPD asserted that the operation of the proposed facility would provide the region with substantial net benefits in the form of reduced system-wide emissions of pollutants due to the displacement of the generation of less efficient, more polluting existing facilities by the proposed facility (Exh. BP-1A at 3-50 to 3-51; Company Brief at 51). To demonstrate environmental benefits realized from the displacement of existing sources of air pollution, the Company presented a dispatch analysis[77] comparing the emissions of the following pollutants associated with the combustion of fossil fuels both with and without the proposed project: (1) sulfur oxides ("SOx"); (2) NOx; (3) particulates ("PM-10"); (4) volatile organic compounds ("VOCs"); (5) CO; and (6) carbon dioxide ("CO_2") (Exhs. BP-1A at att. 3-32; HO-RN-35; HO-RR-44(red.)).

BPD indicated that it used the ENPRO model and plant-specific emissions data[78] to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. BP-1A at 3-50). BPD stated that future CAAA compliance requirements for SOx and NOx were incorporated into the analysis,[79] with the exception of NOx emissions offsets that will be

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77 BPD indicated that the overall methods and assumptions employed in the dispatch analysis of emissions were identical to those employed in the economic efficiency analysis (Exh. BP-1A at 51) (see Section II.A.3.a.i, above).

78 Mr. Graham stated that emission rates for existing units were based primarily on actual emission rates and that emission rates for the generic units were based on recent permitted emission rates for new facilities in the region (Exh. BP-1A at 3-50; Tr. 8, at 38-40).

79 BPD stated that the analysis assumes reductions in existing SOx and NOx emission rates (Tr. 8, at 39). BPD stated that facilities that currently can burn fuels with either low or high sulfur content were assumed to burn the lower sulfur content fuel in order to comply with Massachusetts and CAAA acid rain regulations (Exh. HO-RN-28). In addition, BPD stated that NOx emissions were based on a Northeast States for Coordinated Air Use Management assessment of NOx reduction requirements which differ slightly from the most recent NOx reduction requirements (id.).

(continued...)

required for the proposed facility and generic additions (Exhs. HO-RN-28; HO-RN-31).[80] In addition, as noted in Section II.A.3.a.i, above, BPD assumed that average heat rate and unit availability would remain constant over time,[81] and that dual fuel oil/gas units would burn gas for nine months and oil for three months over the 20-year analysis period (Exhs. HO-RN-28; HO-RN-27).

The Company's dispatch analysis assumes that the proposed project would delay the need for generic capacity and thus displace such capacity (Exhs. HO-RR-79; HO-RN-35; HO-RR-44(red.)). The Company indicated that its dispatch analysis also reflects the difference between the proposed project and generic units in displacing older units (Exhs. HO-RR-79; HO-RN-35; HO-RR-44(red.)).

The Company's analysis demonstrates that, under the 1993 CELT dispatch scenario, operation of the proposed project would provide emissions savings over the 20-year period 1999 through 2018 and would provide emissions reductions for each pollutant for each year with the exception of (1) 2001, when VOC emissions would be increased by one ton, and

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[79](...continued)
The Company noted that improvements in emission rates would more than offset load growth for SOx and NOx emissions between 1996 and 1999, but not for other types of emissions (Exh. HO-RN-51). The Company explained that the CAAA requires a greater percentage reduction in SOx and NOx emission rates from power plants than the projected increase in NEPOOL average net energy for load (id.). The Company further noted that SOx and NOx emissions reductions likely would be achieved by fuel switching and/or capital investments in additional control equipment (id.).

[80] The Company stated that it would be difficult to anticipate the impact of NOx emission offsets on total NOx emissions attributable to electric generation in the region because NOx emissions offsets may not come from within New England or from electric generation (Exh. HO-RN-35). The Company noted that, to the extent that the generic units have higher emissions than the proposed facility, the dispatch analysis may overstate NOx emission reductions attributable to the proposed facility and underestimate the relative costs of the generic facilities (id.).

[81] The Company argued that this assumption is conservative since unit aging and the addition of pollution control equipment would likely result in the degradation of these performance characteristics (Exh. HO-RN-28).

(2) 2006 and 2007, when all emissions would increase (Exh. BP-1A at att. 3-32).[82] See Table 9.

The Company indicated that emissions savings would be greater under the updated 1994 CELT dispatch scenario than under the 1993 CELT dispatch scenario and that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would result in emissions reductions for each pollutant for each year with the exception of (1) 2010, when VOC emissions would increase by one ton, and (2) 2017 and 2018, when all emissions would increase (id.; Exh. HO-RR-44(red.)). See Table 9.

BPD's analysis demonstrates that, under both dispatch scenarios, emissions savings over the first five years of the analysis for all pollutants, with the exception of VOCs, would constitute at least 50 percent of the total savings over the 20-year period (id.). Under the updated 1994 CELT dispatch, emissions savings in 1999 would be greater than the total emissions savings over the next four years for SOx, NOx, CO, and a significant percentage of the total emissions savings over the five-year period, 1999 through 2003, for all pollutants (Exh. HO-RR-44(red.)). See Table 9.

The Company asserted that Massachusetts will require the capacity represented by the proposed facility for environmental purposes (Company Brief at 56). However, the Company indicated that it is difficult to quantify emissions benefits to Massachusetts because (1) emissions may migrate beyond the borders of the state in which they originated, and (2) the generic units have not been assigned to particular locations (Exh. HO-RN-38). The Company stated that, assuming the generic units would be distributed across the region in proportion to sales, emissions displacement allocated to Massachusetts would be slightly less than the 44.5 percent ratio of Massachusetts to NEPOOL net energy for load because Massachusetts is a net importer of electricity (id.).

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82 BPD explained that increases in emissions would result from (1) the difference in the size of the proposed facility and the assumed size increment for the GTCC units, and (2) the relationship between capacity need and the size of the unit added (Exh. HO-RN-33).

b. Analysis

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. Cabot Decision, 2 DOMSB at 326; Altresco Lynn Decision, 2 DOMSB at 99. See also, Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

In the Enron Decision, the Siting Board 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 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. Cabot Decision, 2 DOMSC at 329; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings with those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly dispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million Btu ("lbs/MMBtu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. Cabot Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333.

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. Cabot Decision, 2 DOMSC at 327; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 333. 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 retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation.[83] 1 DOMSB at 333.

Here, the Company has provided a comprehensive 20-year analysis of dispatch effects on regional emissions for the period 1999 to 2018. However, unlike earlier petitioners, BPD has not provided a dispatch analysis that would allow the Siting Board to determine the net impact that the proposed project would have on the total emissions from generation facilities located in Massachusetts. The Siting Board notes that all of the proposed project's emissions are in Massachusetts, and that, absent a dispatch analysis or other means of verifying how much of the displacement will be in Massachusetts, the regional dispatch analysis cannot be used as the basis for a finding of environmental need in Massachusetts. Nonetheless, the Siting Board here evaluates the Company's dispatch analysis and the environmental benefits provided to the region by the proposed project.

The Company's analysis includes sufficient documentation regarding the methods and assumptions used in the calculating the net impact that the proposed project would have on emissions from generation facilities located in the New England region for the Siting Board to evaluate whether there would be significant dispatch-related emissions reductions specific to the operation of the proposed project. In addition, although the Company assumes constant emission rates over time, the Company's analysis takes into account likely emission reductions for SOx and NOx that will be required in 1999 under the CAAA and Massachusetts acid rain regulations.

The Company's dispatch analysis shows a clear net reduction in emissions of all pollutants modelled over the 20-year forecast period, with a large percentage of the reductions occurring in the first five years of operation of the proposed facility. Further, the updated 1994 CELT dispatch scenario shows very significant benefits in the year 1999. The

83 The Siting Board also noted that similarly favorable long-term air quality benefits 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, 2 DOMSB at 101.

Company assumes that 100 percent of the proposed project is sold in 1999 even though, under this dispatch scenario, there is no identified capacity need until 2000. Thus, for the year 1999, the updated 1994 CELT dispatch scenario clearly shows the environmental benefit of displacing existing generation.

Although the dispatch analyses show long-term reductions in emissions, it is not clear whether these reductions would result in permanent benefits and would be directly related to operation of the proposed facility. First, the Company's analysis allows the displaced generation to be increasingly redispatched over time with continued load growth.[84] In addition, as in the economic efficiency analysis, the Company assumes that the proposed project will have a significantly lower heat rate than the generic GTCC units, with associated lower annual emissions throughout the 1999 though 2018 period. Further, the larger 252 MW size of the proposed project, relative to the assumed 225 MW size of the first and later units of GTCC capacity, potentially increases the displacement of oil-fired and other older units in some years of BPD's analysis. Finally, by not incorporating NOx emissions offsets that would be required of the proposed facility and generic facilities, and by assuming a constant fuel mix for the dual fuel units and a consistent heat rate for the generic units, the Company may have overstated emissions reductions due to the operation of the proposed facility in the long-term.

The Siting Board notes that these uncertainties in the dispatch analysis are not susceptible to easy resolution since they relate, primarily, to uncertainties about the attributes of plants that will be built in the distant future. An analysis of air quality benefits works best for the period of time when there is no capacity need and thus, no reason to speculate about the attributes of plants that will be constructed in the future. Therefore, the Siting Board notes that, in the future, it may be appropriate for our review of environmental need to focus on the displacement of older generating units, in the period of time prior to a capacity need.

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[84] We note that for several regional or worldwide air quality concerns, including O_3, acid rain, and climate change, statutory or other policy goals point to a need to avoid or substantially minimize regional or national emissions increases. The pollutants that relate to such concerns include SOx, NOx, VOCs, and CO_2.

Accordingly, the Siting Board finds that: (1) the Company has established that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would provide short-term regional air quality benefits; (2) the Company has not established that operation of the proposed project would provide significant long-term regional air quality benefits; and (3) the Company has not established that operation of the proposed project would provide air quality benefits to Massachusetts.

5. Conclusions on Need

The Siting Board has found that there is a likely need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 1999 and beyond and a clear need for 252 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond. In addition, the Siting Board has found that there is a need for 252 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1999 and beyond.

The Siting Board also has found that, consistent with its findings regarding reliability need in New England, there will be a likely need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 1999 and that there will be a clear need in New England for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000. In addition, the Siting Board has found that there is a need in Massachusetts for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region.

Further, the Siting Board has found that: (1) the Company has established that, under the updated 1994 CELT dispatch scenario, operation of the proposed project would provide short-term regional air quality benefits; (2) the Company has not established that operation of the proposed project would provide significant long-term regional air quality benefits; and (3) the Company has not established that operation of the proposed project would provide air quality benefits to Massachusetts.

Based on a showing of need for 252 MW or more of additional energy resources in the Commonwealth for reliability purposes beginning in 1999 and beyond and a likely need for 252 MW or more of additional energy resources in the region beginning in 1999 and beyond, the Siting Board finds that the proposed project is needed to provide a necessary energy supply for the Commonwealth beginning in 1999 and beyond.

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. Cabot Decision, 2 DOMSB at 334; Altresco Lynn Decision, 2 DOMSB at 107; EEC (remand) Decision, 1 DOMSB at 296.

2. Identification of Resource Alternatives

a. Description

To address the identified need for additional energy resources, BPD proposes to construct a nominal 252-MW gas-fired, combined-cycle facility in Agawam, Massachusetts, which would commence commercial operation in 1999 (Exh. BP-1A at 1-1). The Company stated that it conducted a two-phase screening process to identify all potential alternative technologies and then to identify those technologies that would be practical, cost-effective alternatives to meet the identified need at the proposed site (id. at 4-2 to 4-3; Tr. 5, at 102).

The Company stated that, in the first stage of its screening process, it assessed the feasibility of all electric generation and storage technologies included in the 1993 TAG and 1994 GTF reports, based on the criteria of: (1) technology development status;[85] (2) siting/permitting feasibility; (3) cost effectiveness; (4) diversification from oil; (5) compatibility with baseload/intermediate generation; and (6) potential ability to develop sufficient incremental resources in the region to meet the identified need[86] (Exhs. HO-A-1; HO-A-8; HO-A-12). The Company stated that based on this assessment, it eliminated technologies found to have serious fatal flaws[87] and narrowed the list of potential

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85 BPD stated that the 1993 TAG report includes a technical development rating for each technology which is based on EPRI's confidence in the technical and cost data provided in the report (Exh. BP-1A at 4-13). BPD explained that technologies with significant commercial operating experience, and thus the highest confidence level, are rated as "mature," those with beginning commercial operating experience are rated as "commercial," and those whose concept has been demonstrated but are not considered commercial are rated as "demonstration" (id.). BPD stated that additional 1993 TAG report classifications are "pilot" and "laboratory" and that certain technologies are not even given a rating due to technical immaturity (Exh. HO-A-12). BPD noted that a classification of mature, commercial or demonstration was not considered to be a fatal flaw in this stage of the analysis (id.). The Company further noted that the 1993 TAG report is the most recent available TAG report (Tr. 5, at 9).

86 BPD noted that this criterion was relevant to locally resource-constrained technologies for which there are inadequate incremental resources in the region to meet the identified need, such as geothermal power, hydroelectric power and scrap-tire boilers (Exh. HO-A-12).

87 The Company stated that technologies eliminated from further review due to fatal flaws included: (1) nuclear fission; (2) nuclear fusion; (3) geothermal power; (4) photovoltaic cells; (5) solar thermal; (6) tidal power; (7) ocean thermal; (8) hydroelectric; (9) oil-steam; (10) combustion turbines; (11) diesels; (12) scrap-tire boilers; and (13) storage technologies (Exh. HO-A-12; Tr. 5, at 102).

technologies to include: (1) a GTCC facility;[88] (2) an atmospheric fluidized bed coal ("AFBC") facility; (3) a pressurized fluidized bed coal ("PFBC") facility; (4) an IGCC facility in which coal is converted to gas and then burned in a conventional combined-cycle unit; (5) a pulverized coal ("PC") facility; (6) a wind energy system;[89] (7) a biomass facility using a wood-fired circulating fluidized bed combustion unit; (8) a municipal solid waste ("MSW") facility using a mass burn boiler; and (9) a phosphoric acid fuel cell ("fuel cell") (Exhs. HO-A-12; BP-1A at 4-5 to 4-11).[90]

BPD stated that, in the second stage of the screening process, it assessed the potential of each of the aforementioned technologies to reliably meet the identified need at the proposed site[91] with a reasonable degree of assurance, based on five criteria: (1) technical

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88 BPD indicated that the proposed project differs from a generic GTCC facility in that the cost and performance data for the proposed project were based on the Company's pro forma while the cost and performance data for the GTCC facility were obtained from the 1993 TAG report (Exh. BP-1A at 4-16 to 4-17).

89 The Company assumed a 50 MW wind energy system made up of 143 individual 350 kilowatt units (Exh. BP-1A at 4-8).

90 BPD indicated that where the 1993 TAG report described variations on a technology, the Company considered the best variation of the technology in terms of technical maturity, cost, reliability and environmental impacts (Exh. HO-A-1).

91 The Company indicated that, consistent with previous Siting Board reviews, it assumed that the alternative technologies would be located at the proposed site (Exh. HO-A-2). The Company noted that the proposed site is 40 acres, insufficient to site all of the generic technologies with the exception of the GTCC, MSW and fuel cell units (Exh. BP-1A at 4-13). However, the Company noted that if it acquired additional land immediately adjacent to the proposed site, the site size would increase to 70 acres, which would be a sufficient size for each of the alternative technologies with the exception of the wind energy system (id.).

In addition, Mr. Graham discussed the possibility of packaging a combination of alternative technologies at sites scattered throughout Massachusetts (Tr. 5, at 99-102). Mr. Graham asserted that the costs and environmental impacts of a number of small projects would be greater than those of a single large project (id.).

maturity;[92] (2) reliability; (3) siting/permitting feasibility; (4) cost-effectiveness; and (5) local resource potential (Exh. BP-1A at 4-3, 4-12).

The Company indicated that, in this second stage, it eliminated technologies found to have two or more significant flaws that would likely render them incapable of meeting the identified need (Exh. HO-A-2). Based on its analysis, BPD stated that a wind energy system would not be cost-effective,[93] was classified as a demonstration technology, could not be sited at the proposed site, and could only be sited in areas of high wind (Exh. BP-1A at 4-7 to 4-9). BPD also stated that a biomass facility would be limited in size to 50 MW, would not be cost-effective and must be located close to fuel supplies (id. at 4-10 to 4-11).[94] BPD

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92 The Company stated that, in this stage of the analysis, it assumed that those technologies classified by the 1993 TAG report as "mature" or "commercial" would be sufficiently technically mature to be capable of meeting the identified need with a reasonable degree of assurance and that technologies classified as demonstration would have a significant flaw (Exhs. BP-1A at 4-12 to 4-13; HO-A-12; Tr. 5, at 9). BPD stated that the 1993 TAG report classified: (1) the GTCC and PC technologies as mature; (2) the AFBC, MSW, and biomass technologies as commercial; and (3) the PFBC, IGCC, wind energy, and fuel cell technologies as demonstration (Exh. BP-1A at 4-12).

93 In calculating the cost-effectiveness of the wind energy system, the Company assumed that capital costs would decline from 1992 to 1999, that there would be a federal tax credit for the first ten years of operation, that the annual capacity factor would be 30 percent, and that the peak coincidence factor would equal the annual capacity factor (Exh. BP-1A at 4-8). The Company noted that all other technologies would have annual average capacity factors and peak coincidence factors at least double that of the wind technology (id. at 4-8 to 4-9).

94 BPD stated that the size and efficiency of biomass facilities are limited by availability, transportation costs and heat content of the fuel and that existing units have been bought out by utilities due to high costs (Exh. BP-1A at 4-11; Tr. 5, at 28). BPD also stated that it investigated the use of urban or recycled wood, but concluded that it was unlikely that an adequate and reliable supply of such fuel would be available to supply a generating unit of any significant size (Exh. HO-RR-17). In addition, BPD stated that it reviewed a whole-tree boiler as a technology option, but did not analyze this technology because of its classification as a "pilot" technology and the necessity of being located in close proximity to heavily forested regions with substantial land dedicated to supplying such a plant (Exh. HO-RR-18).

further stated that an MSW facility would be limited in size to 40 MW, would not be cost-effective,[95] likely would have siting/permitting restraints,[96] and must be located close to fuel supplies (id. at 4-9 to 4-10). Finally, BPD stated that fuel cells would not be cost-effective and are classified as a demonstration technology (id. at 4-11). Therefore, the Company eliminated the wind energy system, biomass facility, MSW facility, and fuel cells from further review (id. at 4-14 to 4-15).

Thus, the Company identified five technologies -- one gas-fired technology and four coal-fired technologies -- that would be capable of meeting the identified need in lieu of the Company's proposed project (id. at 4-15). Specifically, the Company stated that the technologies that potentially could meet the identified need include: (1) a GTCC facility with oil backup ("GTCC alternative"), which is the type of technology planned for the proposed project; (2) an AFBC facility ("AFBC alternative") (3) a PFBC facility ("PFBC alternative"); (4) an IGCC facility ("IGCC alternative"); and (5) a PC facility ("PC alternative") (id.).

BPD stated that the GTCC alternative and the AFBC alternative are mature technologies and are the standard generating technology choices for new baseload generation in the northeast (id. at 4-4 to 4-5). BPD also stated that the PC alternative is a mature technology and is commonly used for baseload generation in the United States (id. at 4-7). However, BPD indicated that the PFBC alternative, which uses a pressurized flue gas to

95 In calculating the cost of the MSW facility, BPD assumed a current tipping fee -- the fee paid to owners of MSW facilities for waste disposal -- of $40 per ton, escalated at the rate of inflation (Exh. BP-1A at 4-10).

96 The Company stated that MSW facilities tend to have high toxic air emissions (Tr. 5, at 25-26). The Company also stated that it is unlikely that a new MSW plant would be permitted in Massachusetts without the retirement of an existing MSW plant, due to state policies limiting the use of combustible waste in MSW plants (Exh. HO-RR-19).

improve operating efficiencies relative to the AFBC, and the IGCC alternative are not yet commercially available (id. at 4-6 to 4-7).[97]

b. Analysis

The record demonstrates that BPD used a two-stage screening process to identify potential alternative technologies. In the first stage, the Company appropriately reviewed a wide range of potential generation and storage technologies and, based on reasonable criteria, narrowed its review to include nine technologies encompassing a range of technology types and fuels. In the second stage, the Company reviewed these nine technologies to distinguish those that could reliably meet the identified need at the proposed site with a reasonable degree of assurance and eliminated those technologies that were determined to have significant flaws in two or more of its stated criteria.

The Siting Board notes, however, that it is not clear how the Company chose certain technologies for comparison with the proposed project and eliminated others from further review in its second stage of analysis. The record fails to indicate whether there was a specific nominal levelized cost above which the Company determined that a technology would not be cost-effective in its second stage of analysis. Further, flaws found in the biomass and fuel cell technologies were also present in certain of the technology alternatives included for further review. For example, one reason given by the Company for not evaluating biomass units and fuel cells as technology alternatives to the proposed facility was their small size: multiple units of each technology would be required to generate enough power to meet the identified need of 252 MW. The Company nonetheless evaluated one other alternative technology -- the PFBC alternative -- where the size of generation unit also would require construction of multiple units on-site. The Company also determined that a flaw in the biomass facility was the requirement that it be located close to fuel supplies,

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97 The Company noted that the PFBC technology is currently being demonstrated at a size of 80 MW and that, therefore, three 80 MW units were assumed for the proposed site (Exh. BP-1A at 4-6). BPD also noted that the IGCC technology has been demonstrated in limited applications (id. at 4-6 to 47).

while coal-fired facilities were included in the analysis even though there is no rail line for coal transportation in close proximity to the proposed site. Further, the Company determined that a flaw in fuel cells was their classification as a demonstration technology while the PFBC and IGCC alternatives, also classified as demonstration technologies, were included.

Thus, based on the Company's criteria, it is not clear why the biomass facility and fuel cells were eliminated from further review in the second stage of the Company's analysis, while the PFBC, which arguably has two significant flaws, was retained. Nonetheless, the Siting Board finds that, based on a review of the record information regarding cost and reliability of the biomass and fuel cells, the potential for these technologies to meet the identified need at a reasonable cost is uncertain and BPD's decision to eliminate them from further review is appropriate.

In making this finding, the Siting Board does not intend to suggest that the development of renewable resources would not contribute to a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. On the contrary, the Siting Board recognizes that renewable resource projects may represent a source of electricity with low environmental impacts that contributes to the diversity of the Commonwealth's energy supply. However, the record demonstrates that, at this time, these technologies are not sufficiently developed to represent cost-effective alternatives to the proposed project. The Siting Board expects that renewable resources will supplement, rather than substitute for, the energy provided by the proposed project, and notes that these technologies will merit a more comprehensive review as their costs and reliability improve.[98]

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98 The Siting Board notes that the Department has proposed a series of market-based approaches to ensuring that renewable resources have a meaningful opportunity to compete in a restructured electric industry. Electric Restructuring Order Commencing Notice of Inquiry (NOI)/Rulemaking at 68-78. In particular, the Department has proposed a renewables fund, to be collected through a low, non-bypassable charge on distribution services, that could offset a portion of the (continued...)

Thus, for purposes of this review, the Company has demonstrated that the GTCC alternative, AFBC alternative, PFBC alternative, IGCC alternative, and PC alternative would potentially address the identified need, and in its review of the cost, environmental impacts, and reliability of the proposed project, the Siting Board compares the proposed project to these five alternatives.

3. Comparison of Environmental Impacts

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

The Company indicated that all technology alternatives were compared on the same level of net electric output, 252 MW (Exh. BP-1A at att. 4-2). The Company also indicated that cost and performance data for the proposed project was based on the Company's pro forma while cost and performance data for the technology alternatives were obtained from the 1993 TAG report (id. at 4-16 to 4-17). The Company stated that, compared to the technology alternatives, the proposed project has the highest projected availability factor, 92 percent, and lowest heat rate, less than 7,000 Btu/kWh[99] (id. at att. 4-2) (see Table 11, Section II.B.4.a, below).

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[98](...continued)
difference between the price of power from a renewable energy source and the price that customers are willing to pay. Id. at 69.

[99] The Company considers the heat rate of the proposed project to be confidential. For purposes of the technology comparison, the Company assumed a heat rate for the proposed project of 6,977 BTU/kWh (Exh. BP-1A at att. 4-2).

a. Air Quality

The Company asserted that the proposed project would be preferable to all five alternative technologies with respect to air quality (Company Brief at 63). In support of its assertion, BPD provided an analysis of the average annual emission rates and the annual amount of emissions of sulfur dioxide ("SO_2"), NOx, PM-10, CO, VOCs and CO_2 for the proposed project and the technology alternatives (Exh. HO-RR-10). In calculating emission rates for the proposed project and the GTCC alternative, the Company assumed use of back-up oil with 0.05 percent sulfur content for 720 hours per year[100] (id.). The Company also assumed that the GTCC alternative would meet the same emissions control standards as the proposed facility and thus, would have the same emission rates as the proposed project (Exh. BP-1A at 4-19).

In reviewing the coal-fired technology alternatives, the Company assumed that the AFBC and IGCC alternatives would use high sulfur coal, the PC alternative would use low sulfur coal, and that average annual emissions rates would reflect Lowest Achievable Emission Rate ("LAER") technologies (id. at 4-5 to 4-7, 4-19).

BPD stated that the annual emissions of the proposed project would be substantially lower than the annual emissions from the coal-fired alternatives with two exceptions (1) PM-10 emissions would be lower for the IGCC alternative,[101] and (2) VOC emissions would be lower for the PC alternative (Exh. HO-RR-10). BPD further stated that, although the average annual emission rates of the proposed project and the GTCC are comparable, the annual emissions of the proposed project would be lower, reflecting its lower heat rate (Exh. BP-1A at 4-19). See Table 10.

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100 The Company's pending air permit application is based on use of back-up oil for a maximum of 720 hours per year (Exh. HO-E-26(att.) at 1-1).

101 The Company stated that if a CO catalyst were assumed for the IGCC alternative, PM-10 emissions of the IGCC alternative would be at least as high, or higher, than the PM-10 emissions of the proposed project (Exh. HO-RR-10; Tr. 3, at 27).

Table 10

ALTERNATIVE TECHNOLOGIES - POLLUTANT EMISSIONS

	BPD	GTCC	AFBC	PFBC	IGCC	PC
Ann. average emission rates (lbs/MMBTU)						
SO_2	0.0098	0.0099	0.225	0.225	0.078	0.2
NOx	0.0145	0.0146	0.15	0.15	0.035	0.17
PM-10	0.0183	0.0185	0.018	0.018	0.013	0.018
CO	0.0090	0.0090	0.13	0.13	0.056	0.11
VOC	0.0054	0.0054	0.006	0.006	0.007	0.0036
CO_2	117	117	204	204	204	204
Ann. emissions (tpy), based on assumed availability factor						
Availability Factor	92.0%	88.9%	90.4%	80.8%	85.7%	85.5%
SO_2	69	70	1,594	1,594	553	1,417
NOx	103	105	1,466	1,198	268	1,543
PM-10	130	132	176	144	99	163
CO	64	64	1,271	1,039	429	998
VOC	38	39	59	48	54	33
CO_2 (1,000 tpy)	827	837	1,994	1,630	1,561	1,852

Source: Exh. HO-RR-10

The record demonstrates that, on balance, considering all pollutants, the annual emissions of the proposed project would be lower that those of all of the technology alternatives. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project is slightly preferable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to air quality.

b. Water Supply and Wastewater

The Company asserted that the proposed project and the GTCC alternative would have comparable water requirements and wastewater generation but that each of the coal-fired alternatives would require a significantly greater water supply and would generate significantly greater amounts of wastewater (Company Brief at 64-65).

The Company indicated that both the proposed project and the technology alternatives would require water for cooling tower makeup and process water, and assumed that all technology alternatives would include a wet mechanical cooling system for the steam condenser -- the same as that planned for the proposed project (Exh. BP-1A at 2-2, 4-20). The Company stated that, assuming an 85 MW steam turbine, both the proposed project and GTCC alternative would require 1.392 million gallons per day ("mgd") for cooling tower makeup and 0.084 mgd for process water, including water for steam injection during oil firing, for a total water requirement of 1.476 mgd (Exh. HO-RR-10). The Company stated that, again assuming an 85 MW steam turbine, the IGCC alternative also would require 1.392 mgd for cooling tower makeup, but that a greater amount of process water, 0.654 mgd, would be required for the coal slurry makeup and continuous water injection for NOx control, for a total water requirement of 2.046 mgd (id.; Exh. BP-1A at 4-20 to 4-21). BPD stated that the AFBC, PFBC and PC alternatives each would have greater requirements for cooling tower makeup and process water than the proposed project, in amounts totalling: (1) 4.278 mgd for the AFBC alternative; (2) 3.429 mgd for the PFBC; and (3) 4.468 mgd for the PC alternative (Exh. HO-RR-10).

BPD stated that the proposed project and the GTCC alternative each would generate 0.135 mgd of cooling tower blowdown and 0.052 mgd of process wastewater, for a total of 0.187 mgd of wastewater (id.). In addition, BPD stated that the IGCC would generate the same amount of cooling tower blowdown, but would generate a greater amount, 0.323 mgd, of process wastewater, for a total of 0.458 mgd of wastewater (id.). The Company stated that the AFBC, PFBC and PC alternatives also would generate greater amounts of wastewater than the proposed project, in amounts totalling: (1) 0.542 mgd for the AFBC alternative; (2) 0.435 mgd for the PFBC alternative; and (3) 0.587 mgd for the PC alternative (id.).

The record demonstrates that the water requirements of the proposed project would be equivalent to those of the GTCC alternative and would be approximately: (1) 35 percent of the AFBC alternative's; (2) 43 percent of the PFBC alternative's; (3) 72 percent of the IGCC alternative's; and (4) 33 percent of the PC alternative's. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to water use.

The record further demonstrates that the wastewater generated by the proposed project would be comparable to that generated by the GTCC alternative and approximately: (1) 35 percent of the AFBC alternative's; (2) 54 percent of the PFBC alternative's; (3) 41 percent of IGCC alternative's; and (4) 32 percent of the PC alternative's. Accordingly, the Siting Board finds that, for purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to wastewater discharge.

c. Noise

The Company asserted that the proposed project would be comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to noise impacts (Company Brief at 65-66). Mr. Keast stated that major exterior noise sources at the proposed project would include the intake and exhaust from the combustion turbine, the cooling tower, ventilation openings in the turbine building wall, an exhaust duct, and the HRSG (Exh. BP-DK-3, at 1). Mr. Keast added that the major interior noise sources would include the gas and steam turbine-generators and ancillary equipment (id.).

In comparing the noise impacts of the proposed project to that of the technology alternatives, BPD assumed that each of the technology alternatives could be designed to achieve the same degree of continuous noise mitigation as would be achieved with the proposed project (Exh. BP-1A at 4-21 to 4-22).[102] However, BPD stated that the coal-fired alternatives would have added sources of noise due to coal usage (Exh. HO-RR-38). BPD stated that on-site noise due to coal delivery, including unloading, conveying and crushing, could be mitigated by enclosing the facilities for those operations, but that noise associated with delivery of coal to the site by rail could not be fully mitigated (id.). BPD also stated that the gasification component and flare stack of the IGCC alternative would be additional on-site noise sources, and that it might not be possible to mitigate on-site noise of this alternative to the level of the proposed project (id.).

The record demonstrates that the noise impacts of the proposed project and the GTCC alternative could be mitigated to the same degree. The record further demonstrates that although the on-site noise impacts of the proposed project and the AFBC, PFBC and PC alternatives technically could be mitigated to the same degree, the coal delivery to the site would increase noise impacts of the AFBC, PFBC and PC alternatives relative to the proposed project. The record also demonstrates that the noise impacts of the IGCC alternative are potentially greater than the noise impacts of the other coal-fired alternatives.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project is comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to noise impacts.

d. Fuel Transportation

BPD asserted that the proposed project is slightly preferable to the GTCC alternative and far superior to the coal-fired alternatives with respect to fuel transportation impacts (id. at 4-22 to 4-23; Company Brief at 67). BPD stated that natural gas would be delivered to the site via a new pipeline that would be constructed within public ways and on-site, extending approximately 4,000 feet from the existing Tennessee mainline to the site

102 The Company noted that the AFBC, PFBC and PC alternatives would require larger cooling towers than the proposed project and that cooling tower noise mitigation therefore would be more extensive for these alternatives (Exh. HO-RR-38).

(Exh. BP-1A at 2-5, 4-22). In addition, the Company asserted that back-up fuel oil delivery would not be a significant factor in the overall fuel delivery to the proposed project (id. at 4-22). BPD explained that the proposed project would require a maximum of 991 oil trucks per year, or 33 oil trucks per day for 30 days per year, and that fuel oil deliveries would not exceed a maximum of two deliveries per hour (id.; Exh. HO-RR-10).[103] The Company stated that the GTCC alternative would have comparable fuel delivery requirements but that, due to its higher heat rate, the GTCC alternative would require greater quantities of natural gas and a greater number of oil deliveries (Exh. BP-1A at 4-22 to 4-23).

The Company explained that it selected the proposed site in part due to its proximity to an existing natural gas pipeline in order to minimize the impacts of gas transportation, and noted that a coal-fired facility likely would be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries (id. at 4-24). Therefore, the Company stated that a coal-fired alternative was not a good match for the proposed site due to the lack of existing rail infrastructure at or near the site (id. at 4-23; Exh. HO-RR-10).

However, BPD stated that if a rail route to the proposed site could be identified, construction of a rail connection to the site from the closest existing rail mainlines likely would impact waterways, roadways and residences (Exh. HO-RR-10). The Company stated that the annual number of coal trains required for the coal-fired alternatives, assuming a 100 car unit train, would be approximately: (1) 78 for the AFBC alternative; (2) 64 for the PFBC alternative; (3) 61 for the IGCC alternative; and (4) 72 for the PC alternative (Exh. BP-1A at att. 4-4).[104] The Company stated that the AFBC, PFBC and PC

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103 BPD stated that the proposed project will include an on-site fuel storage tank, sized to store sufficient oil for three days of continuous operation, and noted that it was unlikely that gas would be unavailable for three continuous days (Exh. BP-1A at 4-22). In its pending air permit application, BPD indicated that it expects periods of oil-fired operation would not total more than 100 hours or less in most years (Exh. HO-E-26(att.) at 4-1 to 4-2).

104 BPD stated that if coal were delivered to the site by truck instead of rail, the coal-fired alternatives would require between 98 and 120 trucks per day, or 30,000 to 40,000 trucks per year (Exh. HO-RR-10).

alternatives also would require truck delivery of limestone or lime for SO_2 control amounting to approximately thirteen truck deliveries per day, five days per week, and that the IGCC alternative would likely require a natural gas pipeline for backup fuel (id. at 4-23).

The Company asserted that the overall impacts associated with fuel transportation for the coal-fired alternatives would be greater than those associated with fuel transportation for the proposed project (id.). The Company explained that, even assuming the availability of adequate rail infrastructure, delivery of coal by rail to the proposed site would still involve impacts to other users and to abutting communities and also would present the possibility of accidents (id.).

In comparing the proposed project to the GTCC alternative, the record demonstrates that, due to its higher efficiency, the proposed project would require less natural gas and a smaller number of oil deliveries than the GTCC alternative. The Siting Board notes that the fuel transportation-related impacts of the two projects would not differ on the basis of natural gas delivery but that the smaller number of truck deliveries of fuel oil would produce fewer impacts. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be slightly preferable to the GTCC alternative with respect to fuel transportation.

In comparing the transportation impacts of the coal-fired alternatives to the proposed project, the Siting Board notes that a coal-fired facility likely would be sited in proximity to existing rail lines. Because a potential rail route to the proposed site has not been identified, the specifics of the impacts along such a 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 mitigation strategies have not been addressed. However, rail transport could have traffic and noise impacts over the life of the project. In light of the limited pipeline expansion and overall minimal impacts associated with fuel transportation for the proposed project, rail transport of coal likely would result in greater impacts.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to fuel transportation.

e. Land Use

BPD asserted that the proposed project would be comparable to the GTCC alternative and preferable to the coal-fired alternatives with respect to land use impacts (Company Brief at 67). BPD stated that it evaluated total land requirements and surrounding uses to determine the land use impacts of the proposed project and its alternatives (Exh. BP-1A at 4-25). The Company also stated that the footprint of the proposed project would fit within ten acres of the undeveloped 40-acre site and that the height of the main components would be: (1) 67 feet for the boiler building; (2) 125 feet for the stack;[105] and (3) 50 feet for the cooling tower (Exh. BP-FS-2, at 2-8). The Company stated that the proposed site is located in an industrially zoned area, surrounded by industrial, commercial and residential uses (id. at 2-6).

BPD stated that the GTCC alternative could be designed to fit within the ten-acre footprint of the proposed project and that the height and size of the facility components would be comparable to the proposed project (Exh. BP-1A at 4-25). However, BPD stated that the coal-fired alternatives would require a greater amount of land for facility footprint, rail unloading and fuel storage areas, totalling: (1) 43 acres for the AFBC and PFBC alternatives; (2) 50 acres for the IGCC alternative; and (3) 49 acres for the PC alternative (id.). BPD stated that, in addition, the coal-fired alternatives would require a greater number of structures than the proposed project[106] and that the scale of such structures, including the height of the buildings, stacks and cooling towers, would be significantly larger than the components of the proposed project (id.). However, the Company noted that land use impacts are extremely site-specific and that the coal-fired alternatives generally would be located at larger sites with significantly greater buffer areas.

105 BPD indicated that it has requested that the Massachusetts Department of Environmental Protection ("MDEP") approve a stack height of 125 feet (Exh. HO-E-1(att.) at 2-1).

106 The Company stated that each of the coal-fired alternatives would require structures for coal unloading and handling and that the IGCC alternative also would require a gasification plant and flare stack (Exh. BP-1A at 4-25 to 4-26).

The record demonstrates that the footprint of the proposed project and GTCC alternative would require ten acres within the proposed 40-acre site. The record further demonstrates that the coal-fired alternatives would have footprints of between 34 to 50 acres and would require a greater number of buildings and larger scale buildings than the proposed project. The Siting Board notes that each of the coal-fired alternatives likely could be constructed on the proposed site if available adjacent land were purchased but that a coal-fired alternative likely would be constructed on a larger site, providing a greater buffer between the facility buildings and surrounding uses.

Given the facility footprint and building size requirements of the proposed project relative to the coal-fired alternatives, the land use impacts of the proposed project would be preferable at the proposed site. Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC, and PC alternatives with respect to land use impacts.

f. Solid Waste

The Company asserted that the proposed project would be comparable to the GTCC alternative and preferable to the coal-fired alternatives with respect to solid waste impacts (Company Brief at 68). In support thereof, BPD stated that the proposed project and the GTCC alternative would generate minimal amounts of solid waste, approximately 250 tpy, consisting primarily of incidental office and maintenance waste (Exh. BP-1A at 4-26, and att. 4-6). In contrast, the Company stated that the solid waste generated by the coal-fired alternatives, consisting primarily of ash for the AFBC, PFBC and PC alternatives and slag for the IGCC alternative, would total: (1) 183,000 tpy for the AFBC alternative; (2) 149,500 tpy for the PFBC alternative; (3) 62,000 tpy for the IGCC alternative; and (4) 136,400 tpy for the PC alternative (id.). The Company added that it assumed that solid waste from the coal-fired alternatives would be hauled off-site in railcars and that the ash potentially could be used as back-fill for coal mines (id. at 4-26).

The record indicates that the proposed project and the GTCC alternative would produce significantly less solid waste than the coal-fired alternatives. Further, the large quantities of solid waste produced by the coal-fired alternatives would necessitate numerous rail trips to dispose of the waste off-site, although these rail trips would likely not be incremental. The Siting Board notes that the solid waste impacts of coal-fired technologies frequently can be mitigated by shipping coal ash to the mine head via the return trip of the train that transported the coal to the site. However, the record does not provide details of shipment of solid waste off-site and its effect on rail transport requirements. The Siting Board previously has found that, in the absence of detailed plans for the transport and disposal of solid waste in an environmentally beneficial way, solid waste impacts are greater for those technologies that generate greater amounts of waste. EEC (remand) Decision, 1 DOMSB at 351-352.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be comparable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC and PC alternatives with respect to solid waste impacts.

g. Findings and Conclusions on Environmental Impacts

In comparing the overall environmental impacts of the proposed project and the GTCC alternative, the Siting Board has found that the proposed project would be slightly preferable to the GTCC alternative with respect to air quality and fuel transportation impacts and that the proposed project would be comparable to the GTCC alternative with respect to water use, wastewater discharge, noise impacts, land use impacts and solid waste impacts. Accordingly, the Siting Board finds that the proposed project would be slightly preferable to the GTCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the coal-fired alternatives, the Siting Board has found that the proposed project would be preferable to the AFBC alternative, the PFBC alternative, the IGCC alternative and the PC alternative with respect to air quality impacts, water use, wastewater discharge, noise impacts, fuel transportation impacts, land use impacts and solid waste impacts. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFBC alternative, the PFBC alternative, the IGCC alternative and the PC alternative with respect to environmental impacts.

4. Cost

a. Description

BPD asserted that the proposed project would be clearly superior to each of the technology alternatives with respect to cost (Company Brief at 62). In order to compare costs, the Company explained that it modelled the projected total revenue requirements of each of the alternatives over a 20-year period, with an assumed in-service date of January 1, 1999 (Exh. BP-1A at 4-15).[107] The Company stated that it then summed the NPV of annual revenue requirements and calculated 20-year nominal levelized costs in dollars per kilowatt-hour ("$/kWh") for each of the alternatives (id.).

The Company indicated that the initial cost and performance data for the proposed project were consistent with the Company's pro forma, and initial cost and performance data for the technology alternatives were based on the 1993 TAG report (id.).[108] BPD stated that inflation rates were taken from the 1994 GTF report (id. at att. 4-1). With respect to fuel prices, the Company indicated that the initial fuel price for the proposed project was based on actual quotes and was escalated at five percent annually and that the initial fuel prices for the technology alternatives and escalation rates were obtained from the 1994 GTF report (id., att. 4-1, 4-17; Exh. HO-A-10). BPD stated that it also assumed that the proposed project and the technology alternatives would run constantly, limited only by their availability factors (Exh. BP-1A at 4-16).

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107 In projecting total revenue requirements for each alternative, BPD used consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. BP-1A at 4-1).

108 The Company also calculated the cost of the coal-fired alternatives with lower land costs (Exh. HO-RR-20). The Company indicated that lower land costs made little difference in levelized costs (id.).

Table 11, details the total installed costs,[109] O&M costs, and 20-year levelized costs for the technology alternatives. 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 of the technology alternatives (Exh. BP-1A at 4-17; see also, Exh. HO-A-11).[110]

Table 11

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	BPD	GTCC	AFBC	PFBC	IGCC	PC
Size (MW)	252	252	252	252	252	252
1994 Fuel Price ($/MMBTU)		$2.95	$1.55	$1.55	$1.55	$1.70
Availability Factor	92.0%	88.9%	90.4%	80.8%	85.7%	85.5%
Heat Rate (BTU/kWh)	6,977	7,300	9,796	8,959	8,090	9,618
Total Installed Cost ($1999/kW)		$804	$2,253	$1,868	$2,410	$2,295
Fixed O&M ($1999/kW)		$32.83	$46.73	$53.55	$60.80	$67.44
Var. O&M ($1999/kW)		$0.51	$6.82	$4.17	$0.63	$2.88
20-yr Nominal Levelized Cost ($/kWh)	*	$0.071	$0.084	$0.088	$0.090	$0.097

* The 20-year nominal levelized cost for the proposed project was less than $0.071/kWh.

Sources: Exhs. BP-1A at atts. 4-2, 4-3; HO-A-11.

b. Analysis

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, given the

109 The Company indicated that total installed cost includes total cost of plant, permitting, land, interconnection, allowance for funds during construction, startup and inventory, and working capital (Exh. BP-1A at 4-2).

110 The fuel price, total installed cost, O&M costs, and levelized cost for the proposed project were provided in confidential documents.

Company's assumptions regarding capital costs, interest rates, and fuel prices. The Siting Board notes that the Company's analysis does not provide for future uncertainty in fuel price forecasts. An analysis of the sensitivity of the cost comparisons to changes in fuel prices would have been particularly relevant in this case, since there is no fuel contract for the proposed project.

In addition, 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 project life of 25 or 30 years. Such a comparison would be more favorable to the more capital-intensive technology 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 coal-fired alternatives are higher than the proposed project, the Siting Board recognizes that the use of a 30-year levelized cost could decrease the cost of the coal-fired alternatives relative to the proposed project. See Cabot Decision, 2 DOMSB at 351; EEC (remand) Decision, 1 DOMSB at 375. However, given the significant 20-year levelized cost advantage of the proposed project over the coal-fired alternatives, it is unlikely that a 30-year cost analysis would reverse the relative cost superiority of the proposed project over the coal-fired alternatives.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the GTCC, AFBC, PFBC, IGCC and PC alternatives with respect to cost.

5. Reliability

a. Description

The Company asserted that the proposed project is preferable to each of the alternative technologies with respect to reliability (Company Brief at 68). In assessing the reliability of the proposed project and the technology alternatives, the Company assessed (1) the anticipated availability of each technology and corresponding energy source, and (2) the likelihood that the technology would be available and would operate in accordance with the cost and performance specifications at the time when the first need for new capacity has been identified (Exh. BP-1A at 4-27 to 4-28).

The Company stated that projects that rely on a mature, commercially available technology have a reliability advantage over technologies whose expected cost and performance characteristics have not been fully demonstrated and are based primarily on engineering estimates (id. at 4-28). The Company reported that the combined cycle technology and PC technology are categorized as mature in the 1993 TAG report, giving the proposed project, the GTCC alternative and the PC alternative a reliability advantage over the other technology alternatives under consideration (id.). The Company stated that the proposed project would have an anticipated availability of 92 percent, higher than any of the other technology alternatives (see Table 11, above) (id. at 4-27). In addition, the Company stated that it anticipates securing a firm fuel transportation contract from a point in New York to the proposed project and that, at the option of customers, BPD would arrange for a gas supply or allow the power purchaser to contract for its own gas supply (Exh. HO-RN-57; Tr. 2, at 10-11) (see Section II.C.3.b, below). Thus, the Company concluded that the proposed project is superior to the technology alternatives with respect to reliability (Exh. BP-1A at 4-27).

b. Analysis

The record demonstrates that the availability of the proposed project would be 92 percent and that the technology of the proposed project is classified as mature by the 1993 TAG report. Although the Company has indicated that the proposed project would have a firm transportation contract, the Siting Board notes that the Company has not as yet contracted for firm pipeline transportation, and has indicated that it may consider a contract that is firm for less than 365 days per year. However, the Company has presented a back-up fuel strategy that ensures that the plant can operate even if natural gas is temporarily unavailable (see Section II.C.3.b, below).

In comparing the reliability of the proposed project to the reliability of the GTCC alternative, the Siting Board notes that the availability factor for the GTCC alternative is assumed to be 88.9 percent, 3.1 percent less than that 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 GTCC alternative, does not represent a significant difference for the purposes of this review. In addition, the GTCC technology is classified as mature by the 1993 TAG report. Further, the Siting Board assumes comparable fuel supply arrangements for the two technologies. Accordingly, the Siting Board finds that the proposed project and the GTCC alternative would be comparable with respect to reliability.

In comparing the reliability of the proposed project to that of the coal-fired alternatives, the Siting Board first notes that the record in this case does not address any differences in the reliability of a natural gas supply delivered via pipeline and a coal supply delivered via rail.

In comparing the reliability of the proposed project to the reliability of the AFBC alternative, the Siting Board notes that the availability factor for the AFBC alternative is assumed to be 90.4 percent, 1.6 percent less than that 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 AFBC alternative, does not represent a significant difference for the purposes of this review. However, the proposed project is classified as a mature technology, denoting significant operating experience, while the AFBC alternative is classified as a commercial technology, denoting limited operating experience. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFBC alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the PFBC alternative, the Siting Board notes that the availability factor of the PFBC alternative is assumed to be 80.8 percent, 11.2 percent less than that of the proposed project. This difference in availability between the two technologies is significant when considered in conjunction with the difference in maturity level of the two technologies. While the proposed project is classified as a mature technology, the PFBC technology is classified as a demonstration technology, which indicates that the PFBC technology it is not yet considered a commercial technology. Accordingly, the Siting Board finds that the proposed project would be preferable to the PFBC alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the IGCC alternative, the Siting Board notes that the availability factor of the IGCC alternative is assumed to be 85.7 percent, 6.3 percent less than that of the proposed project. This difference in availability between the two technologies is significant when considered in conjunction with the difference in maturity level of the two technologies. While the proposed project is classified as a mature technology, the IGCC technology is classified as a demonstration technology, which indicates that the IGCC technology it is not yet considered a commercial technology. Accordingly, the Siting Board finds that the proposed project would be preferable to the IGCC alternative with respect to reliability.

In comparing the reliability of the proposed project to that of the PC alternative, the Siting Board notes that the availability factor of the PC alternative is 85.5 percent, 6.5 percent less than that 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 PC alternative, does not represent a significant difference for the purposes of this review. In addition, both technologies are classified as mature. Accordingly, the Siting Board finds that the proposed project and PC alternative would be comparable with respect to reliability.

Therefore, the Siting Board finds that the proposed project would be comparable to the GTCC and PC alternatives and preferable to the AFBC, PFBC and IGCC alternatives with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

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 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 environmental impact, cost, and reliability.

In Sections II.B.3, II.B.4, and II.B.5., above, the Siting Board has compared the proposed project to generating technology alternatives that have been determined capable of meeting the identified need, on the basis of their specific environmental impacts, costs, and reliability. Based on its comparison, the Siting Board has found that the proposed project would be: (1) slightly preferable to the GTCC alternative and preferable to the AFBC, PFBC, IGCC, and PC alternatives with respect to environmental impacts; (2) preferable to the GTCC, AFBC, PFBC, IGCC, and PC alternatives with respect to costs; and (3) comparable to the GTCC and PC alternatives and preferable to the AFBC, PFBC, and IGCC alternatives with respect to reliability.

Accordingly, the Siting Board finds that the proposed project is superior to the GTCC alternative, the AFBC alternative, the PFBC alternative, the IGCC alternative and the PC alternative 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. Cabot Power Decision, 2 DOMSB at 364, 370; Altresco Lynn Decision, 2 DOMSB at 144, 152; 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 power sales agreements. Cabot Power Decision, 2 DOMSB at 358; Altresco Lynn Decision, 2 DOMSB at 136-152; NEA Decision, 16 DOMSC at 378-380.

Here, BPD has argued that the project fully meets each of the Siting Board's viability tests, and that the proposed project will be a viable source of energy (Exh. BP-1A at 5-1).

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 will actually go into service as planned. BPD asserted that a number of factors -- the project's low cost and low environmental impacts, the successful experience of the developers, the interest and commitment of the equipment supplier, and the need for the proposed project at the time of commercial operation, assure that the proposed project is financiable either under the current regulatory system or in a restructured environment (Exhs. HO-V-4; HO-V-6).

BPD asserted that its development team, comprised of PDC, ABB EV and CSC, in association with its project management team, have extensive experience in energy project development, power plant design and construction, and power plant operation (Exh. BP-1A at 1-5). With regard to development and financing experience, the Company reported that the principals of PDC and CSC have been directly involved in three Massachusetts projects (the Altresco-Pittsfield project, the Altresco Lynn project, and the TEC), and one project in China (Exh. HO-V-2). Further, BPD stated that ABB operates in more than 140 countries and is ranked 38th in the Global Fortune 500, with extensive experience in gas-fired combined cycle facilities in the United States totaling approximately 2,334 MW of capacity (id.; Exh. BP-1A at 1-6). The Company stated that ABB EV would provide development and equity funding for the project, as well as general project oversight (Exh. BP-1A at 1-6). In addition, the Company stated that R.W. Beck, the owners' engineer, has been involved in over 350 project-finance projects, both in the United States and abroad (Exh. BP-RC-1, at 5; Tr. 1, at 45). The Company's witness stated that R.W. Beck has experience in engineering, commercial, financial and contractual issues, all of which are necessary to the successful financing of a project (Tr. 1, at 46).

BPD stated that its preferred financing strategy is based on executing long-term contracts under conventional financing (Exh. HO-V-4). BPD explained that projections of the costs and revenues of a project are made based on binding contracts which specify such costs and secure such revenues (Exh. HO-V-5). To demonstrate financiability under conventional financing, the Company provided two pro forma analyses: a base case that assumes 100 percent of the project's capacity is sold under long term contracts, and a low case that assumes 75 percent of the capacity is sold (Exh. HO-V-4(rev)).[111] The Company asserted that the debt coverage ratios ("DCR") in both pro formas are sufficient to achieve financing (id.).[112] Mr. Cotte stated that in a typical project financing, a reasonable DCR average value is 1.25; however, he stressed that lenders consider factors other than DCRs when making financing decisions and that there is no industry-standard minimum DCR (Tr. 1, at 62).

The Company indicated that it also assessed its financiability under a "merchant plant" financing scenario/approach, which assumes no long-term PPAs (id. at 62, 81). The Company explained that the term "merchant plant" financing describes a situation involving unsecured or market risk resulting from uncertainty about the revenue stream necessary to amortize the debt repayment (Exh. HO-V-5). BPD indicated that in assessing financiability under a merchant plant scenario, it is more appropriate to consider return on equity than DCRs, because the focus of an investor's assessment of the success of the project is based on the rate of equity return, which is a function of the future market price of electricity (Exh. HO-V-4). Although the equity component required for merchant plant financing, which BPD

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111 The Company-sponsored pro formas detailed average debt coverage ratios of 1.84 for the base case and 1.38 for the low case (Exh. HO-V-4(rev); Tr. 1, at 66).

112 The Company stated that it conservatively assumed that under the low capacity scenario all capacity not sold under long-term contract would be sold at 1.5 cents/kWh (Exh. HO-V-4; Tr. 1, at 68).

estimates to be 55 percent, is much larger than that required for conventional financing, BPD indicated that it is confident of its ability to obtain the necessary equity (Tr. 1, at 16, 72, 92).[113]

The Company's witness asserted that although no independent power producer ("IPP") has yet been financed using the merchant plant approach, the financial marketplace has been anticipating the use of merchant plant financing for IPPs for the past two years (id. at 78). The Company acknowledged that merchant plant financing has higher financing costs than conventional financing, since the cost of capital is higher due to the larger proportion of equity needed (id. at 58). The Company asserted that the proposed project can absorb the extra financing costs and still be competitive due to the low cost of the proposed facility (id.). Further, BPD asserted that the proposed plant, even if financed as a merchant plant, would be far less expensive than nearly all existing generation facilities (Exh. HO-V-4).

Finally, the Company stated that it is using an innovative marketing strategy based on its issuance of a Reverse Request for Proposals ("RFP") in June of 1995 -- an RFP in which the Company solicited expressions of interest to buy capacity and associated energy from the proposed project (Exhs. HO-V-7; HO-RN-41, at I-1). The Company stated that the responses it received to the reverse RFP exceeded the capacity of the facility, that the responses included a range of offers concerning fuel supply options, and that interest was expressed in equity participation (Tr. 1, at 11-12). BPD's witness asserted that, based on the responses to the reverse RFP, there is enough demand for the proposed project on a conventional project finance basis to go forward with typical project financing (id. at 75-76).

The record indicates that the project proponents have a broad range of experience in overall project development, including financing. The principals of PDC have developed three IPP's that have been approved by the Siting Board. In addition, ABB EV has

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113 The Company listed a variety of possible sources of equity, including commercial lenders, large insurance companies, equity investment funds, and vendors such as fuel suppliers and contractors (Tr. 1, at 50). BPD stated that ABB, which the Company indicated is a global organization of which ABB EV is a part, and ABB EV are willing to commit equity to the proposed project (id. at 50-51).

substantial worldwide experience in the power development field, as well as significant capital resources. Further, R.W. Beck is knowledgeable, and has arranged for both conventional financings for IPPs and other types of energy projects and merchant plant financings for energy projects other than IPPs.

The range of assumptions provided by BPD in its pro formas is generally reasonable and consistent with Siting Board reviews in prior proceedings. The Company's pro formas indicate that the BPD project is financiable based on projections of DCRs for differing levels of capacity sold under long-term power sales under conventional financing. In addition, ABB EV has indicated that it would contribute to the equity needed to finance the proposed facility.

The Siting Board notes that BPD does not have any signed contracts for its output. However, BPD has presented an alternative financing approach in the event that long-term contracts are not signed by financial closing. The success of merchant plant financing is dependent on the market cost of electricity, and the ability of the Company to produce reliable, low cost electricity. The Company has stated that it can produce electricity at a competitive rate. The Siting Board notes that although the Company has reported that the response to its reverse RFP exceeded the capacity of the proposed project, the Siting Board must consider the possible attrition of respondents as the proposed project develops. However, the level of positive responses to the reverse RFP provides an early indication of the level of interest in the proposed facilities's output.

Based on the foregoing, the Siting Board finds that BPD has 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, BPD indicated that it has negotiated a turnkey construction contract ("EPC turnkey contract") with a construction consortium comprised of ABB Power Generation and Black and Veatch Construction, Inc. ("B&V") (Exh. BP-1A at 5-2). B&V

would be the engineering, procurement, and construction ("EPC") contractor and ABB Power Generation, affiliated with ABB EV, would be the equipment supplier for the project and a partner to the EPC contractor (id. at 1-7, 1-9).

BPD asserted that B&V is a world leader in combustion turbine power plant projects with extensive experience as design engineer, construction manager, owner's engineer, and financial institution's engineer (id. at 1-9, 1-10; Exh. HO-V-14). The Company provided information demonstrating that B&V has completed work on more than 20 combined cycle projects in the last ten years, and is slated to complete over 15 more in the next five years, ranging in capacity from 116 MW to 1,350 MW (Exh. HO-V-14). The Company stated that B&V was the lead architect in the development of the ABB GT-24 ACS Combined Turbine Generator ("GT-24") plant (Exh. BP-1A at 1-9). BPD stated that ABB Power Generation is part of a global ABB organization that provides the power industry with power generation, transmission and distribution equipment (id. at 1-8). The Company provided information which indicated that ABB Power Generation has over 1,000 utility and industrial installations using gas turbine and combined cycle systems throughout the world (id. at att. 2-1). In addition, ABB Power Generation developed the first dry low-NOx combustor in 1984 (id. at att. 2-4).

The Company has submitted a Term Sheet, which is the basis for negotiation of the final EPC turnkey contract, that provides the owner with a fixed price for the proposed project based on an agreed scope of work (id. at 5-3; Exh. HO-V-13(att. a)(red.)). BPD stated that, according to the Term Sheet, B&V would be responsible for all design, engineering, procurement, manufacturing, delivery, construction tasks and installation needed to bring the plant into operation at guaranteed output, heat emissions, noise and other performance levels (Exh. BP-1A at 5-3). The Term Sheet, as a precursor to the EPC turnkey contract, contains a set of binding terms and conditions for the engineering and construction of the proposed BPD facility, including provisions for: (1) a lump sum price; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, and (b) operation guarantees; (4) an early completion bonus; (5) warranties; (6) insurance; and (7) acceptance testing (Exh. HO-V-13(att. a)(red.)).

The Company indicated that the first GT-24 is scheduled to undergo nine months of testing in the spring of 1996, and is scheduled for commercial operation in the summer of 1997 at the Gilbert Generating Station in New Jersey (Exhs. HO-V-14; HO-RR-51).[114] The Company stated that the testing of the GT-24 at the Gilbert facility is proceeding as scheduled and that it has not experienced any problems that would affect the ability of the GT-24 to operate as planned (Tr. 1, at 15). BPD indicated that the first GT-24 will have completed approximately three years of operation prior to the commercial operation date for the BPD facility (Exh. HO-V-11). Finally, the Company stated that ABB is not aware of any other gas turbine available in the marketplace that could achieve the performance and emission profiles of the GT-24 (Exh. HO-RR-52). Nevertheless, the Company asserted that ABB has guaranteed the plant's performance and is required to correct any problems or pay liquidated damages (id.).

The Company stated that interconnection to the regional electric transmission grid would be via a 115 kV transmission line which would extend approximately 500 feet across the northern portion of the site, connecting to an existing 115 kV WMECo transmission line (Exh. BP-1A at 2-5). BPD stated that R.W. Beck conducted a detailed interconnection analysis based on load flow studies, which concluded on a preliminary basis that the proposed facility could be reliably interconnected with the existing 115 kV transmission system with limited reconducturing (Exh. HO-V-19). The Company indicated that it will be preparing studies that address additional contingencies, as directed by Northeast Utilities ("NU"),[115] and noted that NU was supportive of the project in preliminary meetings based

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114 The Company indicated that, in addition to the Gilbert facility, ABB will also have a GT-24 operating in Korea at the time of BPD's commercial operation, and the GT-26, which is a scaled version of the GT-24, will be operating in Switzerland, Germany and England (Exh. HO-RR-49). The Company also indicated that the GT-24 is being considered for nine other projects (Exh. HO-RR-50).

115 WMECo is a subsidiary of Northeastern Utilities.

on BPD's initial interconnection and load flow analysis (Tr. 1, at 28-30). BPD's witness stated that, because NU requires a significant deposit before entering into contractual discussions for a final interconnection agreement, the Company would not execute a final contractual agreement with NU until later in the permitting schedule of the project (id.).

The Company provided a letter from the Agawam Superintendent of Public Works that noted the ability of the Town to provide water to the proposed project (Exh. BP-1B at 7-62, (att. 7.3.1)). The Company also stated that option agreements exist between BPD and the owners of the two individual parcels that comprise the proposed project site (Tr. 4, at 17).

In the past, the Siting Board has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is likely to be constructed on schedule and will be able to perform as expected. Cabot Power Decision, 2 DOMSB at 363; Altresco Lynn Decision, 2 DOMSB at 143; Altresco-Pittsfield Decision, 17 DOMSC at 380. Here, BPD has submitted a Term Sheet, the precursor to a final EPC turnkey contract. In addition, the record in this proceeding indicates that B&V and ABB Power Generation have significant experience in the design and construction of plants which use the technology proposed for this project and have successfully completed similar projects.

The Siting Board notes however, that the proposed gas turbine technology, the GT-24, is as yet unproven in commercial operation. While the Company has asserted that the equipment has passed each milestone to date, and that ABB would be responsible for correcting any problems or incur stiff financial penalties, the proposed project cannot go forward as planned if unexpected problems develop with the GT-24. Specifically, the project could miss significant construction milestones, which would delay financial closing, or could fail to meet stringent operating criteria such as the expected low heat rate and low emission rates. The Siting Board notes that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). The Siting Board notes that should the GT-24 be unable to perform substantially as expected, this would constitute a change to the proposed project such that the Company would be required to notify the Siting Board as explained in Section IV, below.

The Siting Board notes that the Term Sheet includes a number of advantageous provisions, such as incentive and penalty terms, which the Siting Board has recognized in previous reviews as ensuring timely and quality construction projects. If the final EPC turnkey contract contains all of the significant provisions included in the Term Sheet, BPD will be able to establish that the proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the Term Sheet, as evidence of a reasonable assurance that the project is likely to be constructed on schedule and will be able to perform as expected.

While BPD has been in contact with NU and has prepared an interconnection and load flow study, BPD has not entered into a signed interconnection agreement with NU 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. However, if BPD provides a signed interconnection agreement, BPD will be able to establish that its proposed project is likely to be capable of being dispatched as expected. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed interconnection agreement between BPD and NU.

Accordingly, upon compliance with the above conditions that the Company provide the Siting Board with (1) a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the Term Sheet, and (2) a copy of a signed interconnection agreement between BPD and NU providing the proposed project with access to the regional transmission system, the Siting Board finds that BPD will have established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives.

The Siting Board has found that BPD has established that its proposed project is likely to be financiable. The Siting Board also has found that, upon compliance with the above conditions relative to a signed EPC contract and a signed agreement for access to the regional transmission system, BPD will have established that its proposed project is likely to be constructed within applicable time frames and capable of meeting BPD performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, BPD 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 reasonable entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Cabot Power Decision, 2 DOMSB at 364-366; Altresco Lynn Decision, 2 DOMSB at 145-146; Altresco-Pittsfield Decision, 17 DOMSC at 381-382. 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 enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. Cabot Power Decision, 2 DOMSB at 366-370; Altresco Lynn Decision, 2 DOMSB at 145-152; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

Here, BPD stated that it has selected ABB Operations and Maintenance Department ("ABB O&M") as its O&M contractor (Exh. BPD-1A at 1-7, 1-11). BPD provided a copy of a draft contract between BPD and ABB O&M for O&M services (Exh. HO-V-13(att. b)(red)). The draft O&M contract contains a set of principal terms and conditions for the operation and maintenance of the proposed facility that encompass both the preliminary mobilization period and operation (id.). In addition, the agreement specifies performance targets for availability, heat rate, capacity, and budget variation, which are tied to an incentive fee (id. at 24).

The Company stated that ABB O&M has extensive experience in the operation of ABB combined cycle equipment, as well as experience providing O&M service for electric utilities (Exh. BPD-1A at 1-11). Specifically, BPD asserted that ABB O&M has over 100 years of experience with rotating equipment, including gas turbines and combined cycle equipment, and over 60 years of electric utility management experience (Exh. HO-V-14; Company Brief at 20). BPD provided information stating that ABB O&M is under contract to manage a total of approximately 4,350 MW, and currently operates eight combined cycle facilities (Exh. HO-V-14). BPD stated that there are significant advantages to ABB O&M operating the GT-24, since ABB designed the GT-24 and is therefore extremely knowledgeable regarding the operation of the equipment (Tr. 1, at 19).

In past cases, 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 its power sales agreements. Cabot Power Decision, 2 DOMSB at 365; Altresco Lynn Decision, 2 DOMSB at 146; Altresco-Pittsfield Decision, 17 DOMSC at 382. Here, BPD has provided a draft O&M agreement with ABB O&M, a qualified vendor who is familiar with the turbine equipment, that includes bonus, penalty, and incentive provisions similar to those reviewed and approved in other Siting Board decisions. The agreement contains sufficient detail to demonstrate to the Siting Board that the project is likely to be operated and maintained in a manner consistent with reliable performance over its expected life if the agreement is signed. If BPD provides an executed O&M agreement, which is identical or similar in all significant provisions to the draft contract with ABB O&M, the Company will be able to establish that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. Therefore, the Siting Board requires BPD to provide the Siting Board with a copy of a signed O&M agreement between

BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract.

Accordingly, the Siting Board finds that, upon compliance with the above condition that BPD provide the Siting Board with a copy of a signed O&M agreement between BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract, BPD will have established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

b. Fuel Acquisition

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures low-cost, reliable energy resources over the terms of its power sales agreements.

BPD asserted that it expects that in a more competitive environment, PPAs likely will be for terms of five to ten years, and that it therefore has developed a range of strategies to ensure reliable transportation and supply to the facility in accordance with the length of expected PPAs (Exh. BP-1A at 5-6, 5-7). The Company's witness, Mr. Corbett, stated that he determined that the project must have firm transportation into New England (Tr. 2, at 10-11). Mr. Corbett selected the intersection of the Tennessee and the Iroquois Gas Pipeline Company ("Iroquois") system at Wright, New York ("Wright") as an appropriate delivery point from which to ensure firm transportation to the project site (id.).[116] Therefore, BPD determined that it would contract with Tennessee for firm transportation

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116 BPD provided a letter from Tennessee which summarizes the status of discussions between BPD and Tennessee (see Exh. BP-DC-3). In addition to Wright, Tennessee presented a number of possible delivery point options including Morrisville, New York, Tennessee's northern storage fields, and the Gulf Coast, as well as downstream options such as the Distrigas of Massachusetts ("DOMAC") facility, and interconnects with the proposed Portland Pipeline Project or the proposed Sable Island Project (id.).

from Wright to the facility in Agawam, either for 365 days per year or for a lesser period of time such as 335 days (Exh. HO-V-16; Company Brief at 23).[117]

BPD stated that it anticipates securing a firm transportation contract in time for financial closing in late 1996 (Tr. 2, at 50). BPD indicated that a Tennessee compressor station is located approximately 4,000 feet south of the proposed primary site, and that Tennessee would construct a new 16-inch interconnection to the proposed facility (Exh. BP-FS-2, at 2-33). The Company asserted that Tennessee would be filing a proposal for the 4,000-feet interconnect with the FERC this year (Tr. 2, at 50).

BPD reported that Tennessee cannot determine at this time whether firm service to the proposed project would require upgrades to the system between Wright and Agawam. However, Tennessee indicated that the costs of any necessary upgrade could be accommodated within the existing tariff rates and would not require an incremental rate (Exh. BP-DC-3; Tr. 2, at 17). BPD asserted that if it signs a contract with Tennessee, Tennessee would be responsible under such contract for transporting the gas from the Wright delivery point to the proposed facility at the designated start date under all circumstances, regardless of the timeframes for any upgrades (Tr. 2, at 19). BPD explained that Tennessee stated it has options for meeting this responsibility in the designated timeframe, such as purchasing gas from DOMAC or from storage-type projects (id.).

In keeping with its goal of flexibility, BPD stated that, at the option of its customers, it would arrange for a gas supply or allow the power purchaser to contract for its own gas supply (Exh. HO-RN-57). The Company explained that the project could also accommodate suppliers of natural gas who would deliver the gas to the proposed project for conversion into electricity (Exh. HO-RN-58). The supplier could then either sell the electricity itself, or have BPD sell the electricity for the supplier's account (id.).

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117 The Siting Board notes that Tennessee's letter does not specify either the level of firm transportation service that BPD has requested, or the level that Tennessee has guaranteed (see Exh. BP-DC-3).

The Company explained that, in its RFP, it offered power based on initial fuel costs for the project as quoted by suppliers for five, 10 and 20 year terms with varying escalator rates, ranging from zero to five percent (Exh. HO-A-10). The Company developed prices based on three options quotes, including: (1) supplies from the Gulf Coast delivered to the Tennessee system; (2) supplies from Alberta, Canada; and (3) supplies delivered at Wright, regardless of origin (Tr. 2, at 32-35). The Company asserted that it would be able to acquire gas supplies to meet the requirements of its PPAs, and that it would make a variety of price options available to its customers (Exh. BP-1A at 5-7). BPD asserted that by tailoring its gas supply purchases to the requirements of its customers, it would minimize cost while retaining flexibility (Company Brief at 25).

BPD stated that it obtained transportation rates and prices from Tennessee, Iroquois, CNG Transmission, and ANR Pipeline (Exh. HO-A-10). Further, BPD stated that recent gas supply developments in New England may provide the Company with secondary gas supply options, including capacity releases from local distribution companies, new pipeline projects such as the Portland Pipeline Project and Sable Island Project, and new sources such as the DOMAC/Trinidad LNG Project (Exh. HO-V-15).[118] The Company asserted that two gas suppliers, Enron Gas Marketing and Natural Gas Clearinghouse, have indicated that they are capable of guaranteeing gas deliveries at Wright for 335 days per year (Exh. HO-V-16).

BPD stated that development of a fuel transportation and supply strategy, day-to-day management of the supply, and administration of the fuel transportation contracts would be the responsibility of Pendulum Gas Services ("Pendulum") (Exh. BP-1A at 1-10). BPD asserted that Pendulum can arrange for the flexible contract scheduling that BPD wishes to offer its clients, noting that Pendulum has had experience servicing multiple contracts through a single meter (Tr. 2, at 74). Further, the Company stated that Pendulum has

118 The Company's witness indicated that the Sable Island Project was expected to be in service by the third quarter of 1999, that the DOMAC project was targeted for January 1999, and that he was not certain of the timeframe for the Portland Pipeline Project (Tr. 2, at 14).

handled daily nominations, contract administration, and asset management in New England (id. at 74).

In the event of a gas supply interruption, BPD indicated that it would use low sulfur (0.05 percent) No. 2 distillate fuel oil as a back-up fuel (Exh. BP-1A at 2-2). BPD's proposed air permit would allow it to burn low sulfur oil for thirty days each year (Exh. HO-E-26(att.) at 4-1).[119] BPD stated that, if necessary, the proposed plant can operate on both gas and oil at different times during a day (id.; Tr. 2, at 72). The Company indicated that it would maintain a three-day supply of No. 2 fuel oil on-site in a nominal 930,000 gallon storage tank (Exh. BPD-1A at 2-2). The Company stated that it would contract with a qualified fuel oil supplier located in the greater Springfield area, to be selected based on its financial stability, on-site storage capacity, diversity of supply, quality control program, environmental and safety performance, and insurance requirements (Exh. HO-V-18).

In the past the Siting Board has viewed favorably gas-fired facilities that have provided signed gas supply and transportation contracts, or fuel supply options that were in advanced stages of completion. Cabot Decision, 2 DOMSB at 369; Altresco Lynn Decision, 2 DOMSB at 150; West Lynn Decision, 22 DOMSC at 72.[120] Such contracts generally have matched the length of the proposed project's power purchase agreements, which

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119 The Company stated in its air permit application that, although it would be permitted to burn 30 days of oil, it expects that it would burn oil for 100 hours or less in most years (Exh. HO-E-26, at 4-1). Further, the Company's witness stated that he expects that the Company would burn oil for approximately 64 hours a year (Tr. 13, at 98).

120 The Siting Board notes that in the past three gas-fired facility cases, each proposed project has contracted for gas on a firm basis for 365 days per year. Cabot Decision, 2 DOMSB at 366; Altresco-Lynn Decision, 2 DOMSB at 146; Enron Decision, 23 DOMSC at 108. The Siting Board further notes that the Altresco-Lynn facility was permitted for only five days of oil per year, and the Enron facility's back-up plans did not include oil-firing. Altresco Lynn Decision, 2 DOMSB at 149; Enron Decision, 23 DOMSC at 113-114. The West Lynn facility had a signed contract for gas on a firm basis for 330 days per year, and was permitted for 55 days of oil per year. West Lynn Decision, 22 DOMSC at 73, 92.

typically have been 20 years. However, the Siting Board notes that, given recent structural changes in the gas industry following the issuance of FERC Order 636, as well as the prospect of future structural changes in the electric industry, a different approach to the Siting Board's review of fuel acquisition may be appropriate.

The Siting Board recognizes that, in considering a petitioner's fuel acquisition strategy, it is appropriate to consider the need for flexibility, the expected shorter timeframe of PPAs in a restructured electric industry, and the industry-wide shift away from long-term gas supply contracts. Nevertheless, the Siting Board must still be convinced that low-cost, reliable energy resources will be available to a proposed project in order to determine that a proposed project will be capable of providing a necessary energy supply consistent with our mandate. Demonstrating that proposed facilities will remain competitive and reliable over time not only provides important security in meeting long term energy needs, but also provides assurances that such facilities will be as fully utilized over their planned lives as possible, thereby helping to minimize the future need for additional new construction and its associated cost and environmental impact.

Accordingly, in applying its standard of review for viability relative to fuel acquisition, the Siting Board will henceforth consider whether an applicant's fuel acquisition strategy reasonably ensures a low cost, reliable source of energy over the planned life of the proposed project.

In reviewing a proposed 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 Board. Cabot Power Decision, 2 DOMSB at 369-370; Altresco Lynn Decision, 2 DOMSB at 150-151; Altresco-Pittsfield Decision, 17 DOMSC at 384-389.

The Company has presented a fuel acquisition strategy that involves (1) the intent to contract for firm transportation from Wright, or a comparable location(s), for at least 335 days per year, and (2) a specific back-up supply plan, including a three day, on-site oil supply with the intent to contract for fuel oil from a supplier in the Springfield area, and the ability to switch to oil for limited operation.

BPD has acknowledged the possible capacity constraints in the New England region and the likelihood of interruptions in service in the region, and therefore has tentatively designated Wright as an upstream delivery point from which firm transportation to the proposed project would be guaranteed. However, it remains unclear whether BPD will contract for 365 days of firm transportation service, or a lesser amount such as 335 days. In fact, based on correspondence provided by BPD with Tennessee, Wright may not be the only designated delivery point from which firm transportation to the proposed facility could be contracted; another upstream location mentioned is Morrisville, New York, as well as Tennessee's northern storage fields. Additionally, in the event that BPD chooses to use one of its identified secondary supply sources, such as DOMAC or Sable Island, BPD may need to contract for a downstream delivery point and downstream transportation.

While BPD has not yet finalized its plans for acquiring firm transportation from a major interconnection point to its proposed site, it has indicated that it will do so in time for the financial closing. In addition, BPD has employed Pendulum, a gas services company with experience in daily nominations, contract administration, and asset management, to be responsible for the daily workings of all of the gas supply and transportation contracts for the proposed facility. Therefore, BPD should have the ability to monitor the different contracts to ensure that the potentially numerous gas transactions are carried out in a reliable, timely and least cost manner.

It is likely that fuel supplies selected by individual customers will be low cost due to the ability to take advantage of a variety of gas suppliers and transportation options. However, the Siting Board finds that a firm transportation contract from a major interconnection point to the proposed project site is essential to ensuring that BPD's gas supply strategy is viable. Therefore, the Siting Board requires that BPD provide the Siting Board with signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location) to the proposed facility, or a comparable arrangement, such as firm deliverability based on transportation from Wright combined with downstream supplies.

The Siting Board notes that, although the Company has submitted an air permit application that, if approved, would allow it to burn oil for a maximum of 30 days per year, the Company asserts that gas will be available for all but between 64 and 100 hours in most years. We recognize that past experience relating to supply of pipeline gas to New England may provide a reasonable basis for the Company's assumption regarding the ability to receive gas in quantities above those contracted for on a firm basis. Here, however, BPD's gas supply strategy includes the potential for a varied mix of contracts with differing terms and conditions. Although Pendulum is highly qualified to monitor the gas supply portfolio for BPD, it is unclear that BPD's proposed gas contract for 335 days of firm transportation from Wright would provide adequate assurance that BPD's expectations regarding minimum use of oil firing in most years would be met. The Siting Board further addresses this issue in Sections III.B.2.a and III.B.4.a, below.

Accordingly, the Siting Board finds that based on compliance with the above condition that BPD provide the Siting Board with a signed firm transportation contract for 335 days or more from Wright (or a comparable location), or a comparable arrangement, BPD will have established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project.

The Siting Board has found that BPD has established that (1) upon compliance with the condition relative to providing a copy of a signed O&M contract, the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) upon compliance with the condition relative to providing a copy of a signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location), or a comparable arrangement, its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project.

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, BPD will have established that its proposed project meets the Siting Board's second test of viability.

4. Findings and Conclusions on Project Viability

The Siting Board has found that upon compliance with the conditions in Sections II.C.2 and II.C.3, above, BPD will have established that (1) 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 planned life of the proposed project.

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, BPD will have established that its proposed project is likely to be a viable source of energy.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Site Selection Process

The Siting Board has a statutory mandate to implement the energy policies in 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 69J. 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.

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. New England Power Company, EFSB 94-1, at 50 (1995) ("1995 NEPCo Decision"); Cabot Decision, 2 DOMSB at 373; 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. 1995 NEPCo Decision, EFSB 94-1, at 54-55; Cabot Decision, 2 DOMSB at 373; Berkshire Gas Company (Phase II), 20 DOMSC at 109 (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.[121] 1995 NEPCo Decision, EFSB 94-1 at 57-59; Altresco Lynn Decision, 2 DOMSB at 144-145; 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 boundaries of the principal steam host. Cabot Decision, 2 DOMSB at 373-374; Altresco Lynn Decision, 2 DOMSB at 165; MASSPOWER Decision, 20 DOMSC at 328.[122]

In the sections below, the Siting Board reviews BPD's site selection process, including its development of siting criteria and application of those criteria, and the geographic diversity of BPD's primary and alternative sites.

2. Development of Siting Criteria

BPD stated that it developed and administered an innovative Site Selection RFP ("SS-RFP") to select a site (Exh. BP-1A at 6-6). BPD stated that its site selection process differs from that of projects previously reviewed by the Siting Board since this is the first time that an RFP has been used to select a site (Company Brief at 70). BPD stated that the

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121 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 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.

122 The Siting Board notes that proposed sites or routes located in the coastal zone as defined under the Massachusetts Coastal Zone Management ("MCZM") program and the Coastal Zone Management Act, 16 U.S.C. § 1453, are subject to additional regulatory requirements. See 980 C.M.R. 9.00. However, the proposed site is not located in the coastal zone, and is not subject to these regulations.

SS-RFP was designed to (1) provide comprehensive project information to potential community bidders, and (2) elicit the data necessary to enable BPD to review identified sites in a systematic and consistent manner, based on comprehensive cost, environmental, and other criteria (Exh. BP-1A at 6-8, 6-9). The Company asserted that its RFP-based site selection process was designed to meet the Siting Board's site selection objectives, in order to ensure the construction of a least-cost, least-environmental impact, reliable facility at a site with demonstrable community support (id. at 6-4; Company Brief at 70).

a. Description

The Company stated that it developed two types of site selection criteria: (1) threshold criteria that each site was required to meet in order to be further considered as a site for the proposed facility, and (2) more detailed evaluative site criteria (Exh. BP-1A at 6-10, 6-15). The Company reported that it developed its criteria and scoring system[123] before it received specific site proposals for consideration from communities (Tr. 4, at 21). BPD stated that its threshold criteria included: (1) location in a municipality with a Tennessee mainline or lateral; (2) location in a municipality with a transmission line of 115 kV or greater; (3) a minimum site size of eight acres with a minimum of seven acres of buildable land; (4) a minimum water supply of 1.5 mgpd available starting in 1999; (5) the ability to discharge up to 245,000 gpd of treated wastewater to a local wastewater treatment plant beginning in 1999; (6) suitable soil to accommodate development of heavy industry; (7) no apparent archaeological or historically significant structures; and (8) no apparent threatened or endangered species or habitat (Exh. BP-1A at 6-10, 6-11).

The Company stated that it also developed major evaluative site criteria, broken down into 13 categories and 31 total subcategories, where each of the 31 subcategories were to be

123 The Company's witness stated BPD had used a screening system based on the evaluation of site attributes, followed by a final selection process based on evaluating the facility impacts at respective sites (Tr. 4, at 46). The Company's witness testified that he had used a variation of this type of system in siting a number of industrial facilities (id. at 17).

individually scored (id. at 6-15, 6-16). BPD explained that the criteria were focused on achieving the objectives of environmental suitability, development compatibility, ease of construction and minimum cost (id. at 6-13). The Company stated that it developed criteria in the following categories to rank the offered sites: (1) earth resources: site base elevation, topography, potential for subsidence or erosion, depth to bedrock, potential for site contamination, and existence of prime agricultural soils at the site; (2) air resources: dispersion environment and interacting sources; (3) water resources: surface water resources, groundwater resources, and floodplain proximity; (4) terrestrial ecology: endangered species/significant habitat; (5) aquatic ecology: mapped wetlands/waterbodies, and significant habitat; (6) land use/zoning: land use compatibility, site zoning designation, proximity to residences and sensitive receptors, and site size and buffering potential; (7) transportation: adequacy of roadway/rail infrastructure, and constraints to roadway capacity; (8) noise: potential for compliance with local or state noise regulations, and distance to sensitive receptors and buffering potential;[124] (9) utilities: electrical interconnection,[125] gas interconnection, water/sewer interconnection, and water supply permit status; (10) community support: level of community support,[126] and willingness of municipality to

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[124] This criteria encompassed both the distance from the property line of the potential site to the nearest sensitive receptor or residentially zoned area, and the distance from the footprint of the proposed project to the nearest sensitive receptor (Exh. BP-1A at 6-28). The Company indicated that sensitive receptors are places of worship, hospitals, nursing homes, and schools (id. at 6-24).

[125] A site received: (1) a high ranking for electric interconnection if an existing 115 kV line was located within one mile of the site boundary, interconnection would not involve significant upgrades, and all upgrades would be within the host community; (2) a medium ranking if interconnection would require moderate upgrades, but the site otherwise would receive a high ranking; and (3) a low ranking if the nearest existing transmission line was located more than one mile from the site, or if interconnection would require either significant upgrades or upgrades in more than one community (Exh. BP-1A at 6-29).

[126] The Company stated that site suitability ratings for the level of community support criteria were based on support by elected officials, response to the SS-RFP, media (continued...)

execute tax agreement; (11) socioeconomics: compatibility with community development objectives; (12) visual resources: project visibility and compatibility with viewshed, and site buffering/mitigation potential; and (13) cultural resources: degree of historical or archaeological significance (id. at 6-16 to 6-34).

The Company ranked each criterion as either very important, of moderate importance, or of minor importance (id. at 6-14, 6-35).[127] The Company then evaluated each potential site by assigning suitability ratings of high (3 points), medium (1 point) or low (0 points) for each criterion (id.).[128] Finally, the Company developed an overall suitability score for each site by developing a weighted average of individual suitability scores, such that each very important criterion contributed five percent of the overall score, each moderate criterion contributed 2.5 percent, and each minor criterion contributed 0.5 percent (id. at 6-35, 6-36; Tr. 4, at 14, 15).

b. Analysis

The Siting Board notes that the majority of its past generation facility reviews have concerned cogeneration facilities. However, the Siting Board previously has stated that the site selection criteria developed for an IPP should be similar to criteria developed for a cogeneration facility, except for the steam host locational requirement. Enron Decision, 23 DOMSC at 127. Here, BPD has developed a broad array of criteria which address the critical issues associated with the siting of generating facilities and which are generally consistent with the site selection criteria which the Siting Board has found to be appropriate

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[126](...continued)
response, and the community's historical response to heavy industrial development (Exh. BP-1A at 6-31)

[127] Of the 31 evaluative criteria, 13 were determined to be very important, 13 were determined to be of moderate importance, and 5 were determined to be of minor importance (Exh. BP-1A at 6-35, 6-36).

[128] The Company stated that it chose a 3:1 weighting in order to reward sites with very positive attributes (Tr. 4, at 13, 44).

in previous reviews. Cabot Decision, 2 DOMSB at 380-381; Altresco Lynn Decision, 2 DOMSB at 169; MASSPOWER Decision, 20 DOMSC at 378-379.

The Siting Board has concerns regarding three of the specific criteria used to rank sites. First, the Siting Board notes that one of the Company's criteria for noise impacts takes into account the distance to residentially zoned areas but not to individual residences. Thus, the noise ratings may not reflect the proximity of residences that are not located in residentially zoned areas, but nonetheless would be designated as residential receptors for purposes of noise analyses.

Second, the Siting Board notes that, while the Company's criteria for evaluation of the level of community support includes important factors such as the support of elected officials and media support, these factors alone may not present a complete picture of community support. The Siting Board recognizes that no large industrial project will receive unanimous local community support. However, a site that is selected with significant input from local citizenry is less likely to encounter grassroots opposition, and such input has not been fully captured in the stated criteria.

Third, the Siting Board notes that BPD's electrical interconnection criteria do not adequately reflect the cost and environmental issues associated with a electric interconnect of a significant distance, such as the 4.5-mile interconnect at the alternative site. These criteria fail to distinguish between relatively short (just over a mile) and relatively long interconnections, except when the longer interconnection crosses into another community. In the future, BPD and other petitioners should assess electric interconnection impacts in a manner that more fully considers the length of the interconnect.

After developing a set of evaluative criteria, BPD assigned varying weights to the these criteria based on the level of importance of each criterion in the selection of a suitable site. The Company then developed a scoring mechanism by detailing specific indicators that define the ranking of a site for each criterion. The Company thus incorporated a systematic qualitative approach to comprehensively evaluating site attributes based on their relative importance for ensuring a least-cost, minimum-environmental-impact project.

Overall, by following a comprehensive weighting and scoring system, BPD has addressed the Siting Board concerns raised in previous decisions regarding the need for quantifying weights and scores as part of a site selection criteria. 1993 BECo Decision, 1 DOMSB at 57-58; Enron Decision, 23 DOMSC at 127; MASSPOWER Decision, 20 DOMSC at 378-379.

Accordingly, the Siting Board finds that BPD has developed a reasonable set of criteria for identifying and evaluating alternative sites.

3. Application of Siting Criteria

a. Description

BPD indicated that prior to the issuance of the SS-RFP, it determined that it was necessary to locate the proposed facility in western Massachusetts (Exh. BP-1A at 6-5; Tr. 4 at 64).[129] The Company explained that it then selected 23 communities in western Massachusetts in which either a Tennessee mainline or major lateral was located, and sent information describing the proposed project to these communities with instructions to return an "expression of interest" letter if they wished to be considered as a host site for the proposed project (Exh. BP-1A at 6-5, 6-8). BPD stated that it received twelve letters of interest requesting copies of the SS-RFP, and that eleven communities responded to the SS-RFP, offering one or more sites, for a total of 20 sites (id. at 6-8, 6-12).[130]

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129 The Company stated that in the earliest stages of project development, the Company selected southern New England as a potential location for its project and then focused on western Massachusetts (Exh. BP-1A at 6-4). BPD identified three reasons for selecting western Massachusetts: (1) the ability to locate in close proximity to a natural gas pipeline without capacity constraints; (2) the ability to locate in close proximity to major electric transmission facilities; and (3) the ability to minimize wheeling charges by interconnecting with a utility that does business with many other utilities (id. at 6-6).

130 The following communities responded to the SS-RFP: Adams; Agawam (5 sites offered); Chesire; Easthampton; Holyoke; Lanesborough; Lee; North Adams; Pittsfield (2 sites offered); Southwick (5 sites offered); and Westfield (Exh. BP-1A at 6-12).

The Company asserted that its use of a SS-RFP helped address the potential problem of lack of community support which can contribute to delays, increase permitting costs, or even end a project (Exh. HO-S-4). The Company reported that Agawam and Southwick demonstrated verified community support through endorsement letters from elected and appointed officials, and that Agawam also provided endorsements from its Chamber of Commerce (Tr. 4, at 18).[131]

Based on the responses to the RFP, the Company determined that all of the proposed sites met the threshold criteria described in Section III.A.2.a., above (id. at 8). A team led by Earth Tech and consisting of members of BPD, B&V, and ABB conducted site reconnaissance surveys[132] of between one and two hours to assess potential engineering constraints, environmental features, and interconnection alternatives at each of the sites (Exhs. HO-S-13; BP-1A at 6-15). The Company then applied the 31 evaluative criteria to develop weighted scores for each site, and developed a short list of sites based on the site suitability rankings (Exh. BP-1A at 6-15).

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131 The Company reported that it met with elected officials, community leaders and business leaders in Southwick on November 10, 1994 and in Agawam on January 12, 1995 (Exh. HO-S-16). BPD stated that it met with the Southwick officials prior to the Town of Southwick's response to the SS-RFP to present information concerning the proposed project (Tr. 4, at 24, 25). BPD also met with residents of Losito Lane, in Agawam, at the residents' request on January 11, 1995 (id. at 26; Exh. HO-S-16). The Company held a public hearing in Agawam on March 15, 1995 to answer questions and receive comments (Exh. HO-S-16; Tr. 4, at 27, 28).

132 The Company stated that, prior to the site reconnaissance visits, each site was located on geographic information system maps and nearby roadways, airports, waterways, electric transmission lines, the Tennessee mainline, major gas laterals, groundwater wells, surface water reservoirs, designated open space areas, state-designated Areas of Critical Environmental Concern, state Natural Heritage Endangered Species Program priority habitat areas, MDEP approved and interim Zone II protection areas, MDEP permitted solid waste facilities, and areas of complex terrain were identified (Exh. HO-S-13).

The Company indicated that it selected a short list of five sites, and conducted more extensive site visits to the top three sites, designated Agawam 4/5, Agawam 1/2,[133] and Westfield (Exhs. HO-S-13; HO-S-20). BPD then conducted an in-depth engineering review of the short-listed sites to determine the environmental impacts, costs and engineering issues associated with developing the proposed facility at each site (Tr. 4, at 45). Based on these site visits and the engineering review, BPD selected Agawam 4/5 as its primary site and Westfield as its alternative site (Exh. BP-1A at 6-38).[134] After being notified in May, 1995 that the Westfield site was no longer available, the Company conducted an extensive site visit at a fourth short-listed site, known as Southwick 1,[135] and selected the Southwick 1 site as its new alternative site (Exh. HO-S-20).

b. Analysis

The Siting Board previously has stated that the site selection process for an IPP generally should involve the consideration of a broader range of alternatives than other proposed energy projects since an IPP is not constrained by the necessity to locate in a specific area. Enron Decision, 23 DOMSC at 129. Here, the Company issued an SS-RFP soliciting prospective sites from a targeted group of communities, with an approximately 50 percent response rate. The record indicates that all 23 sites offered in response to the

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133 In response to the SS-RFP, Agawam submitted five sites (Exh. BP-1A at 6-12). The Company stated that it combined adjacent parcels where the combination would result in a higher suitability score (id. at 6-36). Agawam sites 1 and 2 were combined to form one site, Agawam 1/2, and Agawam sites 4 and 5 were combined to form a second site, Agawam 4/5 (id.).

134 The Company noted that Agawam 4/5 and Agawam 1/2 were 2,000 feet apart, and would not provide sufficient geographic diversity if chosen as the primary and alternative sites (Exhs. BP-1A at 6-37; HO-S-6). Therefore, the Company stated that it selected the optimal Agawam site for its primary noticed site (Exh. BP-1A at 6-37, 6-38).

135 The Company indicated that the other remaining short-listed site, known as Agawam 3, had been withdrawn in December 1994 since it was unavailable for purchase or lease (Exh. BP-1A at 6-37).

SS-RFP met the threshold criteria established by the Company. The Company applied its evaluative criteria in a comprehensive manner, and scored the sites methodically. BPD then utilized both the weighted score rankings and a follow-up facility impact analysis based on in-depth site visits to determine that the primary site was superior to the other sites.

In the past, the Siting Board has recommended that both the local community and local government be included in an open, participatory site selection process from the inception of a project. Altresco Lynn Decision, 2 DOMSB at 173. Here, BPD has attempted to incorporate local input through its SS-RFP, through meetings with local leaders and residents, and through a public hearing. It is clear that an SS-RFP can be a valuable tool for siting power plants, and that BPD's use of the SS-RFP and its initial discussions with business and community leaders represent a significant attempt to assess local support for its project. However, the SS-RFP necessarily assesses local government support for a project, rather than the support of the community as a whole. The Siting Board stresses that such support is only one component of community acceptance. The Siting Board therefore recommends that, in future site selection processes, project proponents develop better methods for assessing grassroots support for a project site, perhaps through public informational meetings early in the selection process. If possible, this assessment should be included in the evaluative site criteria.

Nonetheless, based on the foregoing, the Siting Board finds that BPD has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior sites.

4. Geographic Diversity

In this section, the Siting Board considers whether BPD's site selection process included consideration of site alternatives with some measure of geographic diversity. BPD asserted that it has identified at least two noticed sites with some measure of geographic diversity (Exh. BP-1A at 6-40). The Company explained that, early in the site selection process, it noticed that the two sites ranked first and second were located 2,000 feet apart in

Agawam, and determined that designating these sites as the primary and alternative sites would not meet the Siting Board's geographic diversity standard (id. at 6-37; Exh. HO-S-6). The Company then compared the two Agawam sites in order to select the better Agawam site for its primary noticed site and selected a site in another town, namely Southwick, for its alternative site (Exh. BP-1A at 6-37, 6-38). The primary site and alternative sites are located in adjacent towns, approximately three miles apart (Exh. HO-S-22(att.)).

The Siting Board requires that an applicant must provide at least one noticed alternative with some measure of geographic diversity. 1995 NEPCo Decision, EFSB 94-1 at 50, 59; 1993 BECo Decision, 1 DOMSB at 64; 1990 Berkshire Decision, 20 DOMSC at 181-182. The Siting Board notes that there is no minimum distance that is sufficient to establish geographic diversity in any given case. The Siting Council has previously determined that two sites in the same town can provide adequate geographic diversity for a generating facility review. Enron Decision, 23 DOMSC at 130; NEA Decision, 16 DOMSC at 385-388. Further, in a transmission line case, the Siting Council stated that simple quantitative diversity thresholds were not appropriate for evaluating geographic diversity. New England Power Company, 21 DOMSC 325, 393 (1991). Here, BPD has provided two sites located three miles apart in neighboring towns with significantly different environmental characteristics, such as site size and natural resource conditions.

Accordingly, the Siting Board finds that BPD has identified at least two practical sites with a sufficient measure of geographic diversity.

5. Conclusions on Site Selection Process

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

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

B. Comparison of the Proposed Facilities at the Primary and Alternative Sites

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, 1 DOMSB at 37-38; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

An 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; EEC Decision, 22 DOMSC at 334, 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; EEC Decision, 22 DOMSC at 334, 336. 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 specific facility proposals. Cabot Decision, 2 DOMSB at 389; Altresco Lynn Decision, 2 DOMSB at 177; 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 review must be clearly described and consistently applied 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.[136] Cabot Decision, 2 DOMSB at 389-390, 421-422; Altresco Lynn Decision, 2 DOMSB at 177, 214; 1993 BECo Decision, 1 DOMSB at 39-40, 154-155, 197. 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. Cabot Decision, 2 DOMSB at 390; Altresco Lynn Decision, 2 DOMSB at 178; 1993 BECo Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental impacts of the proposed facilities at the Company's primary and alternative sites to determine (1) whether the Company's proposal minimizes specific sets of environmental impacts, and (2) which site is preferable based on each specific set of environmental impacts. The Siting Board then examines the cost of the proposed facility, including costs of further mitigation,

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136 The Siting Board notes that project proponents are required to submit to the Siting Board a 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 impacts of the facility in terms of its effect on the natural resources described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 C.M.R. § 7.04(8)(e).

in order to determine whether an appropriate balance would be achieved among conflicting environmental concerns and among environmental impacts, costs and reliability. Finally, the Siting Board compares the two sites to determine which is preferable with respect to providing a necessary energy supply for the Commonwealth at the least cost with a minimum environmental impact.

2. Environmental Impacts

a. Air Quality

i. Applicable Regulations

The Company indicated that regulations governing air impacts of the proposed facility include National Ambient Air Quality Standards ("NAAQS") and Massachusetts Ambient Air Quality Standards ("MAAQS");[137] Prevention of Significant Deterioration ("PSD") requirements; New Source Review ("NSR") requirements; and New Source Performance Standards ("NSPS") for criteria pollutants (Exh. BP-1B at 7-4). The Company further indicated that the proposed facility will fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. HO-E-26(att.) at 3-2).

The Company indicated that under NAAQS, all geographic areas are classified as attainment, non-attainment or unclassified for six criteria pollutants: SO_2, PM-10, NOx, CO, ground-level ozone ("O_3") and lead ("Pb"). The Company further indicated that, although the Agawam area is classified as "attainment" or "unclassified" for SO_2, PM-10, NOx, CO and Pb, the entire Commonwealth of Massachusetts is in serious non-attainment for O_3.[138] The Company indicated that under PSD requirements, the proposed project must (1) demonstrate compliance with NAAQS, and (2) apply Best Available Control Technology ("BACT") to NOx, CO and PM-10, pollutants for which emissions may potentially exceed 100 tpy. The Company indicated that under NSR requirements, the proposed facility must

137 The MDEP has adopted the NAAQS limits as MAAQS.

138 The Company indicated that O_3 is a regional pollutant resulting from NOx and VOC emissions (Exh. BP-1A at 7-19).

apply LAER technology and emissions offsets to any directly emitted pollutant which is a precursor to O_3, and which the proposed facility may emit at levels greater than 50 tpy. Thus, the Company must apply LAER technology to control NOx. With regard to NSPS requirements, the Company indicated that emissions of regulated pollutants -- NOx and SO_2 for the proposed facility -- would fall significantly below threshold levels.

The Company noted that the proposed facility would also incorporate BACT for SO_2, Pb and VOCs, pollutants regulated as part of the MDEP air plans approval process.

ii. Primary Site

(A) Emissions and Impacts

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants, and CO_2 (Exhs. BP-FS-2, at 3-10, 3-27 to 3-30; HO-E-26(att.)). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of efficient technology, clean fuels, BACT, acquisition of offsets and facility dispatch (Exh. BP-1B at 7-48; HO-E-26(att.) at 4-1 to 4-14) (see Section II.A.4, above).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility on the basis of information from government data centers, from manufacturers and vendors of equipment, and from literature reviews (Exhs. HO-E-26(att.) at 4-1 to 4-14; BP-FS-2, at 3-16). The Company provided calculations of air emissions for the proposed facility for two scenarios, one which assumes natural gas firing for 365 days per year at 100 percent load, and a second which assumes 720 hours' firing of low-sulfur distillate oil and natural gas firing for the remainder of the year, all at 100 percent load (Exhs. BP-1B at 7-22; BP-FS-2, at 3-16, Table 3.1-5; Tr. 3, at 16-17). The Company stated that it did not anticipate that the proposed facility would use oil for more than 100 hours per year in most years (Exh. HO-E-26(att.) at 4-1 to 4-2). The Company asserted, however, that the proposed project was likely to operate as a merchant power plant and therefore required the ability to use oil for up to 720 hours per year (id.).[139]

The Company maintained that the proposed facility as designed would incorporate BACT for CO, PM-10, SO_2, Pb and VOCs, and LAER for NOx (Exh. BP-1B at 7-10 to 7-11). The Company asserted that emission rates for non-criteria pollutants and sulfuric acid would also represent BACT (Exh. HO-E-26(att.) at 4-11). The Company provided supporting information regarding control options for criteria and non-criteria pollutants, including a discussion of trade-offs between control of CO and PM-10, and control of NOx, VOCs and CO, to back its contention that assumed facility emission rates would represent BACT and/or LAER for the identified pollutants (id. at 4-1 to 4-13, Table 4-2; Tr. 3, at 8-11, 14-17, 32-37, 82-83, 86-94, 97-101, 107-108, 112-115; Tr. 9, at 1-16).

The Company asserted that predicted air pollutant concentrations resulting from emissions from the proposed facility would be "insignificant" relative to ambient air quality standards (Exh. BP-1B at 7-27). In support of its assertion, the Company provided local air quality modeling results[140] indicating that impacts of the proposed facility on ambient

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139 The Company asserted that without the ability to use oil for up to 720 hours per year, the proposed facility would lack the flexibility to produce power at the lowest possible cost (Exh. HO-E-26(att.) at 4-1 to 4-2; Tr. 3, at 95-96) (see Section II.C.3.b, above).

140 The Company indicated that it relied principally on the Industrial Source Complex Short Term ("ISCST2") and the COMPLEX1 models to calculate emissions at various locations and heights relative to the stack and plume of the proposed facility (Exhs. BP-1B at 7-27; HO-E-26(att.) at 5-1). The Company stated that when ISCST2 screening level modeling of emissions from the proposed facility yielded concentrations above significant impact levels ("SIL"), the Company conducted refined analyses (Exh. HO-E-26 at 5-10). The Company also indicated that for complex terrain, i.e., terrain above stable plume height (as differentiated from "simple" terrain which is below stack height and "intermediate" terrain which is above stack height and below stable plume height), CTSCREEN modeling was performed for those pollutants for which COMPLEX1 modeling produced concentrations above significant impact levels (id. at 5-20; Exh. BP-1B at 7-27).

concentrations of criteria pollutants would be below SILs, assuming a stack height of either 167.5 feet,[141] or 125 feet (Exh. HO-E-26(att.) at 5-9 to 5-24).[142]

The Company also provided predicted ambient concentrations of air toxics from the proposed facility with a 167.5 foot stack and with a 125-foot stack (Exhs. HO-E-26(att.) at 5-25; HO-RR-9(att.)). The Company indicated that the concentrations were derived by scaling from the refined level ISCST2 and CTSCREEN model results for SO_2 (id.).[143] Based on its analysis, the Company stated that concentrations of air toxics from the proposed facility with a 125-foot stack would be below applicable standards[144] for all cases except the 24-hour average predicted concentration for formaldehyde (Exhs. HO-E-26(att.) at 5-25; HO-RR-9(att.); Tr. 3, at 12-14). The Company stated that if the 125-foot stack height were approved by MDEP, the Company would meet an emission limit of 0.00193 lb/MMBtu for formaldehyde to ensure the proposed project's compliance with the TEL for formaldehyde (Exh. HO-RR-9(att.) at Table 5-16).

The Company asserted, citing supporting documentation, that ambient concentrations from its proposed facility, notably predicted annual contributions of SO_2, would have no negative impacts on sensitive vegetation and soils (Exh. BP-FS-2, at 3-36 to 3-37). The Company further asserted that the maximum predicted contributions of SO_2 from the

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141 For the proposed facility, a stack based on Good Engineering Practice ("GEP") guidelines would be 167.5 feet high (Exh. HO-E-26(att.) at 5-8). Use of GEP stack height minimizes building downwash effects (id.).

142 The Company's analysis indicates that ambient concentrations of criteria pollutants emitted from the proposed facility when gas-fired, measured in micrograms per cubic meter and expressed as a percentage of SILs, would range from less than one percent to as much as 13 percent assuming a 167.5-foot stack, and from less than one percent to as much as 48 percent assuming a 125-foot stack (Exh. BP-FS-2, at 3-28).

143 Scaling was performed by dividing the SO_2 concentration by the SO_2 emission rate and then multiplying by the emission rate for each air toxic (Exh. HO-E-26(att.) at 5-25).

144 Applicable standards are MDEP Threshold Effects Exposure Limits ("TELs") and annual average Allowable Ambient Limits (Exh. HO-E-26(att.) at 5-25).

proposed facility, even assuming a 125-foot stack and distillate oil firing, would be insignificant relative to existing ambient concentrations (id.; Tr. 9, at 23 to 24).

(B) Offset Proposals

The Company indicated that, to comply with non-attainment NSR for NOx, it would obtain NOx offsets at a minimum ratio of 1.2 to 1.0 (Exh. HO-E-26(att.) at 4-13). The Company noted that, as implemented by MDEP, offsets are generated by obtaining MDEP-certified Emission Reduction Credits ("ERCs") in an amount five percent greater than that needed based on the 1.2 to 1.0 ratio, i.e., a total ERC requirement of 1.26 times maximum facility NOx emissions (id.). The Company stated that, based on the expected facility emissions of 109 tons per year, the proposed facility will require 137 tons of NOx ERCs per year (id. at 4-2, 4-13). The Company asserted that the most viable sources of offsets for the proposed project would be from future shutdown or curtailment of existing electric generating plants (Exh. HO-E-1(att.) at 2-2 to 2-3). The Company indicated that, because the market in Massachusetts for NOx ERCs was in its infancy, the Company's primary plan was to acquire the necessary ERCs through its power sales process (id.).[145]

The Company indicated that the proposed project would emit 796,430 tpy of CO_2[146] and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. HO-RR-10, at rev. att. 4-5; BP-FS-2, at 3-29 to 3-30). The Company argued that several factors would contribute to the minimization of CO_2 impacts from the proposed facility: the proposed facility's low heat rate; the Company's plan to distribute a significant number of trees annually, coupled with negligible

145 The Company stated that, because offsets might not be available through its power sales process, the Company was pursuing acquisition of offsets from other sources (Exh. HO-E-1(att.) at 2-2 to 2-3).

146 The Company indicated that this emission rate is based on 64 hours per year of oil burning (Exh. BP-1A at 4-18). Assuming the maximum oil-fired generation of 720 hours, the Company indicated the proposed facility would emit 826,418 tpy of CO_2 (Exh. HO-RR-10).

tree-clearing required for construction of the proposed facility; and the displacement, as a result of the operation and dispatch of the proposed facility, of between 1.6 million and 4.4 million tons of CO_2 over the facility's 20-year life (Tr. 9, at 97-98; Company Brief at 79-80). The Company also asserted that its proposed purchase of NOx offsets from a source shutdown or curtailment would result in collateral CO_2 offsets (Exh. BP-1B at 7-35).[147]

The Company provided information regarding a program it had begun in 1995 to distribute approximately 4,000 seedlings each year on Earth Day, consistent with commitments by BPD to Town officials (Exh. HO-RR-59; Tr. 9, at 97-105, 102). The Company stated its willingness to continue this program for the life of the project and indicated that it considered its seedling distribution program to be part of its strategy to offset CO_2 emissions associated with the proposed facility (id. at 97-98).

The Company indicated that curtailment or shutdown of oil-fired capacity sufficient to provide BPD's required NOx offsets would provide CO_2 offsets amounting to 91,700 tpy, or 11.5 percent of BPD's annual CO_2 emissions (Exh. BP-1B at 7-35).[148] However, due to uncertainties regarding the availability of CO_2 offsets, BPD committed itself to providing curtailment/shutdown offsets amounting to only one percent of BPD's CO_2 emissions, or to doubling its seedling distribution program to 8,000 seedlings per year in lieu of such offsets (Tr. 13, at 62-63; Company Brief at 81).

The Company stated that CO_2 offsets are not required under any regulatory program other than the Siting Board review (Tr. 9, at 132-133). BPD noted that the United States has established a goal of holding or reducing annual CO_2 emissions to 1990 levels by the year 2000, consistent with an agreement among the United States and other nations at the 1992

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147 The Company stated that if NOx offsets were obtained in any fashion that would not generate collateral CO_2 emission reductions, the Company would likely rely on a more traditional tree-planting approach, such as the one required in past Siting Board decisions, or on implementation of its seedling distribution program to offset CO_2 emissions (Exhs. HO-E-26(att.); HO-RR-59; Tr. 9, at 97-105).

148 Collateral CO_2 offsets would be at a smaller but comparable level for the shutdown or curtailment of a gas-fired or coal-fired source (Exh. HO-RR-55).

Earth Summit in Rio de Janeiro (Tr. 9, at 65, 97). BPD provided the U.S. report Emissions of Greenhouse Gases in the United States, 1987-1994, which indicates that CO_2 emissions in the United States increased from 4.82 billion metric tons ("bmt") in 1987 to 5.04 bmt in 1990 to 5.24 bmt in 1994 (Exh. HO-RR-58(att.) Table ES1).[149]

The Company indicated that the United States Department of Energy administers the Climate Challenge Program, a voluntary program for the registration of electric utility industry efforts to control emissions of greenhouse gases, such as CO_2 (Exh. HO-RR-56). BPD asserted that its proposed CO_2 offset measures are consistent with the intent of the Climate Challenge Program, although to date BPD has not pursued participation in the program (id.).

iii. Alternative Site

The Company stated that applicable air quality regulations, proposed facility emissions and control technologies, existing ambient air quality, offset proposals, and impacts to vegetation and soils would be the same for the proposed facility at either the primary or alternative sites (Exh. BP-1B at 8-3). The Company provided modeling results indicating that air quality impacts from operation of the proposed facility at the Southwick site would be greater than those at the Agawam site (id.). Based on its analysis, the Company asserted that the Agawam site would be preferable to the Southwick site with regard to air quality impacts (id. at 8-6). In its comparison, the Company assumed construction of the proposed facility with a 167.5-foot stack at both the Agawam and Southwick sites. The Company explained that the higher predicted air quality impacts at the

149 The Company's dispatch analysis indicates that, for a range of load forecasts and assumed supply sources, without the BPD project, CO_2 emissions from electric utility sources in New England would total 39.8 to 43.9 million tons in 1999, increasing to a total of 66.8 to 100.4 million tons in 2018 (Exhs. BP-1A at att. 3-32; HO-RR-44(red.)). With inclusion of the BPD project as a supply source, the corresponding amounts of CO_2 emissions would total 38.8 to 43.7 million tons in 1999, increasing to a total of 67.0 to 100.3 million tons in 2018 (Exhs. BP-1A at att. 3-32; HO-RR-44(red.)). See Section II.A.5, above.

alternative site reflect the relatively higher land elevations in proximity to that site (id. at 8-5).

iv. Analysis

(A) Emissions and Impacts

The Company has demonstrated that emissions of criteria and other regulated pollutants from the proposed facility at either the primary or the alternative site would have acceptable impacts on existing air quality. However, the Company has provided separate estimates of emissions assuming 365 days of gas firing and assuming dual fuel firing including 720 hours of oil firing. In addition, the Company has provided separate analyses of air quality impacts for the proposed facility with a 125-foot stack and a 167.5-foot stack which indicate that air quality impacts of the proposed facility at both sites would be lower with a 167.5-foot GEP stack.

The Siting Board notes that BPD proposes to use a 125-foot stack at the primary site in order to reduce visual impacts at that location (see Section III.B.2.c, below). However, the record indicates that local ambient air quality impacts would be marginally higher with a lower stack. Thus, the Company has not selected a facility design which results in the lowest ambient air quality impacts.

In addition, the Siting Board notes that in the three most recent gas-fired facility cases, each project developer had contracted for gas on a firm basis for 365 days per year. Cabot Decision, 2 DOMSB at 366; Altresco Lynn Decision, 2 DOMSB at 146; Enron Decision, 23 DOMSC at 108.[150] Here, BPD expects to rely on limited periods of oil-fired

[150] The Siting Board notes that the Altresco Lynn facility was permitted for only five days of oil firing per year, and the Enron facility's back-up plans did not include oil-firing. Altresco Lynn Decision, 2 DOMSB at 149; Enron Decision, 23 DOMSC at 113-114. The Cabot facility was permitted for 30 days of oil firing although use of its permitted low sulfur fuel oil for the maximum of 30 days was allowed only in the event of emergency situations, when both liquified natural gas and natural gas were not available. Cabot Decision, 2 DOMSB at 366. The Siting Board specifically (continued...)

generation -- specifically, periods of such generation that BPD expects would amount to 100 hours or less in most years. Further, BPD maintains that it needs to retain the ability to operate on oil for a maximum of 720 hours per year, in the event gas deliveries are curtailed for such periods under possible terms of gas supply and transportation contracts. Finally, as discussed in Section II.C.3.b, above, BPD indicates that it likely would rely on more than one gas contract to supply the proposed facility, with potentially different terms and conditions. Thus, the record in this case does not present the same assurances as provided in recent reviews of generating facilities that oil-fired operations would be substantially minimized.

Accordingly, based on its review of the Company's analysis of emissions and local air quality modeling, the Siting Board finds that the Company has not established that air quality impacts of the proposed facility at the primary site would be minimized. The Siting Board will review the balance between air quality impacts, visual impacts, and cost in Section III.B.4, below.

With respect to air quality impacts at the alternative site, the Siting Board notes that even with a GEP stack of 167.5 feet at Southwick and a 125-foot stack at Agawam, air quality impacts from the proposed facility are predicted to be slightly higher at the Southwick site, reflecting differences in topography at the two locations. The Siting Board therefore finds that the primary site would be slightly preferable to the alternative site with respect to air quality.

(B) <u>Offset Proposals</u>

The Company has presented offset analyses for NOx and CO_2 -- pollutants which potentially contribute to regional O_3 concerns and national and international climate change concerns, respectively. With respect to NOx, the Company has established that it has a

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[150](...continued)
addressed the issue of its expectation that fuel oil substitution for economic reasons would not occur. <u>Id.</u>

viable plan in place to obtain NOx ERCs consistent with non-attainment NSR and MDEP requirements.

The Siting Board first established in the Enron Decision the requirement that all proponents of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 impacts. 23 DOMSC at 196. In its Eastern Energy Corporation Final Decision on Compliance with Environmental Conditions, 25 DOMSC 296, 358-360 (1992) ("EEC Compliance Decision"), the Siting Board required future applicants to present a comprehensive analysis of alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, in order to demonstrate that all cost-effective approaches have been considered. Further, the Siting Board set forth the general criteria it would consider in determining the adequacy of CO_2 mitigation, including the relationship of that mitigation to factors such as facility cost, facility CO_2 emissions, and any increment of such emissions exceeding the emissions of displaced capacity. Id., 25 DOMSC at 361-365. Finally, the Siting Board stated that, in determining the appropriate CO_2 mitigation level based on the above criteria in a particular case, it would consider the balance between the interest of CO_2 mitigation and other interests, including cost, viability, other environmental mitigation and any facility benefits such as supply diversity. Id., 25 DOMSC at 365.

In the EEC Compliance Decision, the Siting Board required the petitioner to commit \$2 million for CO_2 mitigation, with an unspecified allocation between an in-state shade tree planting program and a more cost-effective identified approach of participation in a local, national or international reforestation program. Id., 25 DOMSC at 365-367. In two later generating facility reviews for which initial petitions had been filed prior to the establishment of the general standard in the EEC Compliance Decision, the Siting Board held that a CO_2 commitment comparable to that required in the EEC Compliance Decision was appropriate, but determined comparability based on the tons of emissions to be offset as a percentage of total emissions, rather than based on cost.[151] See Cabot Decision, 2 DOMSB at 397; Altresco Lynn Decision, 2 DOMSB at 183-184.

We note that the levels of CO_2 offsets in past reviews, although accepted as the appropriate balance between environmental impact and cost based on the record in such reviews, represent the mitigation of less than one percent of facility emissions. The record in this review establishes that the United States has set and continues to pursue a goal of holding or reducing emissions to 1990 levels. The record further establishes that CO_2 emissions have increased nationally in recent years, and that such emissions from electric utility sources in New England are projected to increase significantly over the life of the proposed facility.

A number of years have passed since the Siting Board set forth its above-mentioned general standard for CO_2 mitigation. There may now be opportunities to provide CO_2 mitigation that would be significantly more cost-effective than that accepted in past Siting Board reviews, and at the same time, provide a higher level of CO_2 offsets that better establishes that CO_2 impacts would be minimized. The Siting Board now has before it the first generating facility petition filed after the establishment of the general standard for CO_2 mitigation in the EEC Compliance Decision. BPD has identified two forms of environmental mitigation to offset CO_2 emissions: (1) contracted shutdown or curtailment of existing CO_2 sources through direct or collateral purchase (with the purchase of NOx ERCs) of CO_2

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151 To determine the commitment that was comparable to that in the EEC Compliance Decision, for purposes of these later reviews, the Siting Board assumed that 0.8 percent of total facility emissions would be offset by the required cost commitment in the EEC Compliance Decision. Altresco Lynn Decision, 2 DOMSB at 186, 219. However, because facility construction in the EEC Compliance Review was to involve significant on-site tree clearing -- an impact that would negate approximately 56 percent of the required CO_2 offsets -- the Siting Board concluded that applicants in such later reviews could meet the comparability requirement based on attaining a net CO_2 offset level, after adjusting for any on-site tree clearing. Id., 2 DOMSB at 219. Thus, given a facility that was to require no on-site tree clearing, the Siting Board determined the comparable CO_2 offset commitment to be 0.348 percent of total facility emissions. Id.

offsets, and (2) implementation of a seedling distribution program. In addition, based on its 20-year dispatch analysis, BPD asserted that its project would displace generation that otherwise would emit 10-28 percent more CO_2 than the proposed facility over that period.

In setting forth its CO_2 mitigation plan, the Company initially proposed both (1) to acquire offsets that would be collateral to NOx ERCs, amounting to up to 11.5 percent of facility CO_2 emissions, (conservatively estimated at a cost of up to \$411,000 to \$685,000), and (2) to distribute 4,000 seedlings per year for 25 years (at a total cost of \$250,000 to \$375,000). However, BPD has since modified its proposed mitigation to either (1) obtaining offsets of one percent of BPD CO_2 emissions from shutdown or curtailment of existing generation facilities plus distribution of 4,000 seedlings per year, or (2) distribution of 8,000 seedlings per year.

The Siting Board notes that BPD's seedling distribution program would provide a level of CO_2 offsets that is generally comparable, on a cumulative long-term basis, to the offset levels associated with tree planting arrangements accepted by the Siting Board in the past. Specifically, BPD would provide either 100,000 or 200,000 seedlings over 25 years, representing annual offsets that would amount, by the twentieth year of facility operation, to either 0.275 or 0.550 percent of total facility emissions. The Siting Board notes that an annual offset level of 0.550 percent of facility emissions, the higher offset level identified by BPD, would be a clear increase above the net annual offsets required by the Siting Board in past reviews.

The Siting Board also notes that BPD's alternative approach of acquiring CO_2 offsets from curtailment or shutdown of existing emission sources could provide a significantly greater level of offsets at a cost similar to that of tree planting arrangements previously accepted by the Siting Board. Thus, offsets from curtailment or shutdown of existing emission sources may be significantly more cost-effective than such tree planting arrangements.

However, the record does not provide information as to the specific offset arrangement BPD would implement to provide its proposed offsets from curtailment or shutdown of existing sources. While there are existing or evolving markets for offsets or emission reduction credits for pollutants, such as NOx, no such market exists or is planned for CO_2 offsets. Further, the Company has not demonstrated that its proposed purchase of CO_2 offsets would lead to source shutdowns or curtailments that would not occur absent such purchase. Thus, BPD has not established that its proposed purchase of offsets from the shutdown or curtailment of existing sources would lead to proven, incremental reductions in CO_2 emissions.

Therefore, the Siting Board concludes that the Company's proposed distribution of a total of 200,000 seedlings, or a comparable tree planting approach, will provide more certain offset of CO_2 emissions from the proposed facility. We note, however, that at the identified distribution rate of 8,000 seedlings per year for the expected life of the facility, the seedling distribution program would provide offsets amounting to only 0.218 percent of facility emissions within five years of facility start-up, i.e., by 2004. Accelerated implementation of the Company's proposed seedling distribution plan would provide an increased measure of mitigation of CO_2 emissions from the proposed facility during the actual years of facility operation.

In a previous review of a generating facility in which a similar contribution to a tree-planting program was proposed over a 40-year period -- the anticipated life of the facility in that review -- the Siting Board determined that a more up-front payment schedule extending over the first three-to-five years of operation would be more appropriate. EEC Compliance Decision, 25 DOMSC at 365. The Siting Board noted that its determination was due, in part, to the fact that earlier payments would help ensure that the CO_2 offsets provided by the carbon uptake of planted trees would be more fully available during the early years of operation of the reviewed facility. Id.

Here, any acceleration of the proposed seedling distribution program must be consistent with BPD's commitment to the Agawam Planning Board to distribute 4,000 seedlings every year over a 25-year period encompassing the proposed facility's anticipated 20-year life. In addition, the cost of 200,000 seedlings is more readily financed over a 25-year period than during the first five years of the proposed facility's operation.

The accelerated distribution of 60,000 seedlings -- half of the seedlings BPD would distribute during the final 15 years of the 25-year program -- would provide more timely offset of CO_2 emissions, while also allowing the Company to meet its seedling distribution obligation to the Town of Agawam. Accordingly, the Siting Board requires BPD to provide CO_2 offsets through an annual seedling distribution program or a comparable tree planting or forestation program, or combination thereof, so as to attain an annual offset level equivalent to 0.385 percent of annual facility emissions within five years of facility start-up and 0.550 percent of annual facility emissions within 20 years of facility start-up.

The Siting Board notes that the CO_2 offset level required herein, although larger than that required in earlier reviews of gas-fired generating facilities, still represents a small percentage reduction amounting to less than one percent of facility emissions. We recognize that BPD has attempted to develop a more cost-effective CO_2 mitigation approach, offsets based on shutdown or curtailment of existing sources, which potentially would allow a significantly larger offset level. The Siting Board encourages BPD and future applicants to pursue the development of a program to provide offsets from shutdown or curtailment of existing sources.[152]

To accept a program based on shutdown or curtailment of existing sources as part of an applicant's CO_2 mitigation plan, the Siting Board would require submission of sufficient supporting information to allow it to conclude that the program likely would lead to proven, incremental reductions in CO_2 emissions. Specifically, an applicant should demonstrate either (1) that it would acquire CO_2 offsets or emission reduction credits via a market that is operative or planned within an identifiable timeframe, and that is linked to meeting criteria for CO_2 emission limitations or reductions in the United States or other applicable region, or (2) that it would purchase CO_2 offsets that would lead to a source shutdown or curtailment which would not occur without such purchase.

152 In fact, the Siting Board's general standard of review for CO_2 mitigation requires applicants to present a range of CO_2 mitigation approaches to ensure that all cost-effective approaches have been adequately considered and evaluated. EEC Compliance Decision, 25 DOMSC at 360.

Should BPD develop a specific plan to purchase CO_2 offsets based on shutdown or curtailment of existing sources in an amount equal to one percent or more of the proposed facility's emissions, which offsets would lead to proven, incremental reductions in CO_2 emissions consistent with the criteria set forth herein, the Siting Board would accept implementation of such a plan in lieu of implementation of the required mitigation based on seedling distribution, set forth above. BPD should provide the Siting Board with a detailed description of any such specific plan that it intends to implement.

Accordingly, the Siting Board finds that BPD has established that implementation of its offset plans, with inclusion of the requirements herein, would be consistent with a minimization of environmental impacts with respect to air quality.

b. Water-Related Impacts

In this section, the Siting Board addresses the water-related impacts of the proposed facility, including: (1) the water supply requirements of the facility and related impacts on affected water supply systems and on wetlands and other water resources; (2) the water-related discharges from the facility, including wastewater discharges and discharges from on-site stormwater management facilities, and related impacts on wastewater systems and on wetlands and other water resources; and (3) the construction impacts of the proposed facility and associated interconnection facilities on wetlands and other water resources.

The Company stated that average water use for the proposed facility would be 1.45 mgd during gas firing (Exh. BP-1B at 7-62). The Company indicated that the maximum water usage by the proposed facility would be approximately 1.82 mgd, occurring under peak summer conditions and gas-fired operation (id.).[153] The Company also

153 The Company stated that water use for the proposed facility would be slightly higher during oil firing than during gas firing, but that oil firing would likely be limited to the coldest months of the year (Exh. BP-1B at 7-62).

indicated that water for the proposed facility would primarily be used for process water (id. at 7-62 to 7-63).[154]

The Company stated that a number of features had been incorporated into the design and operation of the proposed facility to reduce its water use, including the use of dry low-NOx combusters for NOx control, the choice of an ion exchange system for the demineralizer system, and reliance on water from the Agawam municipal system for circulating makeup water (Exh. BP-FS-2, at 4-11). The Company indicated that it chose not to incorporate certain additional measures to reduce water consumption of the proposed facility, including recycling of steam cycle blowdown and use of water discharged from the stormwater oil-water separator, because these measures presented other negative impacts to operation of the proposed facility (id.).

The Company provided an analysis comparing water use and other impacts of the proposed facility with dry cooling and wet cooling technology (id. at 4-8 to 4-11). The Company indicated that dry cooling requires no water for an evaporative cooling process (id. at 4-8). The Company stated, however, that use of dry cooling is generally confined to locations where a supply of cooling water is not available, because of the lower plant efficiency relative to evaporative systems and the much higher costs of dry cooling (id.). The Company also indicated that the noise impacts of dry cooling are greater than the noise impacts of wet cooling, and are difficult and costly to mitigate (id. at 4-10).

The Company asserted that the use of dry cooling is unwarranted for the proposed facility, citing the disadvantages of dry cooling and the availability of an adequate water supply for the proposed facility (id.). The Company asserted that the available water supply could meet the water supply needs of the proposed facility without adverse environmental impacts or community impacts to the existing infrastructure, other current or future users of that infrastructure, or the underlying water resources (id.).

154 The Company stated that process water included cooling tower make-up water, boiler feedwater, and plant equipment service water (Exh. BP-1B at 7-62 to 7-63).

i. Primary Site

(A) Water Supply

The Company's preferred option for meeting its water supply needs at the primary site was through the Agawam municipal water supply system ("Agawam municipal system") (Exh. BP-1B at 7-62). The Company stated that the proposed facility would interconnect with the Agawam municipal system at an existing 16-inch line at Franklin Street (Exhs. BP-FS-1(att. A) at 2; BP-FS-2, at 3-73). The Company indicated that the proposed interconnection would require a new interconnect line, approximately 6,300 feet in length, in order to ensure that the water supply needs of the proposed project would be met without adverse impacts on the Agawam municipal system (Exh. BP-FS-2, at 2-33 and 3-73; Tr. 12, at 146).

The Company noted that the Agawam municipal system is supplied by the City of Springfield, and that the main source of the Springfield water supply is the Cobble Mountain Reservoir ("Cobble Mountain") in Blandford (Exh. BP-1B at 7-62 to 7-63). The Company asserted that water withdrawals from Cobble Mountain for the proposed project would not cause the Springfield system to exceed the determined safe yield[155] of Cobble Mountain or any other system supplies, and would not change the frequency of water releases from Cobble Mountain to the Little River (Tr. 12, at 50-53). The Company indicated that the determined safe yield of Cobble Mountain is 55 mgd, and that the City of Springfield's registered MDEP withdrawal is 37.2 mgd (Tr. 10, at 58; Tr. 12, at 92). The Company further indicated that in 1994, the most current year for which data was available, the City of Springfield's average daily water use from Cobble Mountain was 34.71 mgd and its maximum daily water use was 52.20 mgd (Exh. HO-E-41(rev.); Tr. 12, at 64). The Company stated that withdrawals from Cobble Mountain by the City of Springfield have declined in recent years, from a high average daily use of 42.64 mgd in 1988 (Exh. HO-E-

155 The Company stated that the safe yield is the amount of water available to be withdrawn from a given resource without jeopardizing the supply of water itself (Tr. 12, at 52).

41(rev.); Tr. 12, at 64).[156] The Company also stated that withdrawals from Cobble Mountain for the proposed project would be less than the amount of the decrease in withdrawals from Cobble Mountain in recent years (Tr. 12, at 51-53).

BPD indicated that the determined safe yield of the entire Springfield system is 92 mgd (Tr. 10, at 58). The Company stated that it had examined water use projections for communities included in the Pioneer Valley Water Action Plan that rely on the Springfield system (Tr. 12, at 60).[157] These projections indicated that the maximum daily use for customers in the City of Springfield would be approximately the same in 2010 as in 1995 but that water use would increase in surrounding communities that rely on the Springfield system (Exh. HO-RR-67(a)(att.); Tr. 12, at 59, 66).[158]

In the Certificate on the FEIR for the proposed facility, the Secretary of Environmental Affairs cited public comments indicating that the proposed facility would have caused the City of Springfield to exceed its MDEP registered maximum withdrawal based on 1993 usage data (Exh. HO-E-1(supp.)). The Certificate also cited MDEP's comment that the registered maximum withdrawal is well below the reservoir's safe yield, and recommended that municipal planners and MDEP work together to determine whether the addition of the BPD project warrants an increase in the registered withdrawal (id.). MDEP, in comments on the Company's Draft Environmental Impact Report ("DEIR"), also recommended that BPD develop a long-term emergency water use plan, which would incorporate alternative

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156 The Company indicated that the City of Springfield's maximum daily use declined from a high 76.50 mgd in 1988 (Exh. HO-E-41(rev.); Tr. 12, at 64).

157 The Company indicated that, in addition to the City of Springfield, the Springfield municipal water system presently serves, in whole or in part, the surrounding communities of Ludlow, Agawam, East Longmeadow, Longmeadow and Southwick, and in the past has also sold water to the City of Westfield (Tr. 12, at 66).

158 Maximum-day demand of Springfield customers was projected to be 55.35 mgd in 1995 and 55.61 mgd in 2010 (Exh. HO-RR-67(a), Table 3). However, total maximum-day demand in the five surrounding communities was projected to be 24.64 mgd in 1995 and 31.66 mgd in 2010 (id.).

sources to relieve the Springfield municipal supply in the event of excessive drought conditions (Exh. BP-FS-3).

With respect to the frequency of water releases from Cobble Mountain to the Little River, Trout Unlimited asserted that the use of approximately 1.5 mgd from Cobble Mountain to meet the water needs of the proposed facility was not advisable (Exh. TU-1, at 1).[159] In support of its assertion, Trout Unlimited submitted a copy of a letter, along with two accompanying photographs of a dry streambed, from Jeffrey J. Balicki, an abutter of the Little River since 1987 (id. at (att. B)).[160] In his letter, Mr. Balicki reported that releases from Cobble Mountain to the Little River, which previously had occurred daily, were discontinued in 1993, and that, thereafter, the Little River "dried up" and "deteriorated both physically and biologically" (id.).

In response, the Company stated that discharges to the Little River have occurred when the water level is higher than the dam at Cobble Mountain and have not occurred when the dam is in drawdown condition, i.e., when the height of the water in Cobble Mountain is below the top of the dam (Exh. TU-1(att. A); Tr. 12, at 50-51). The Company noted that, according to the City of Springfield, intermittent flow conditions have occurred at the Little River since about 1931, when Cobble Mountain was constructed (Exh. TU-1(att. A); Tr. 12, at 44). The Company referred to correspondence from the Springfield Municipal Water Department indicating that, based on the analysis of Springfield's consultants, the ecology of

159 Trout Unlimited noted that it neither supported nor opposed the proposed facility (Exh. TU-1, at 1).

160 Trout Unlimited stated that the photographs were taken during the first week of August, 1993, at the Northwest Road Bridge on the Little River in Westfield (Exh. TU-E-5). Trout Unlimited also provided a copy of a portion of a U.S. Geological Survey topographical map, marked to show the location of the two photos accompanying the letter from Mr. Balicki (id.).

the Little River had long ago adjusted to an intermittent flow pattern (Exh. TU-1(att. A); Tr. 12, at 50).[161]

The Company also stated that the average daily amount of the proposed facility's water use, approximately 1.5 mgd, would translate to a surface water depth at Cobble Mountain of 2/100 of an inch (Tr. 12, at 79; Tr. 13, at 52-60). Based on this small change in surface water depth, the Company argued that wind direction would have greater impact on the amount of water spilling over the dam than would the daily amount of water withdrawn for the proposed project (Tr. 12, at 79; Tr. 13, at 52-60; Company Brief at 93-94).[162] The Company acknowledged, however, that during the transition from a period of high flow to a period of no release -- a "shoulder period" -- water use by the proposed facility might logically be expected to affect the amount of water spilling over the dam (Tr. 12, at 81-85).

BPD also presented information regarding two alternatives to its preferred option for meeting the water supply needs of the proposed facility at the primary site (Exh. HO-RR-71 (supp.)). The two alternatives were to withdraw water (1) from groundwater wells ("groundwater well option"), and (2) from the Connecticut River, via an intake pipe

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161 The Company asserted that the question of releases from Cobble Mountain to the Little River was not directly related to the proposed project but was, instead, a reservoir management issue between Trout Unlimited and the City of Springfield (Tr. 12, at 123; Company Brief at 94). The Company further asserted that the City of Springfield could both release water to the Little River more frequently and meet the water supply needs of the proposed facility (Tr. 12, at 123; Company Brief at 94).

162 The Company asserted that BPD's water withdrawal from the Springfield system would be less than the decline in withdrawals from the Reservoir, "so there could be no drop in frequency of releases based on what has been observed historically with respect to the correlation between withdrawals from the Reservoir and releases to the Little River" (Company Brief at 94).

("Connecticut River option") (id.; Tr. 12, at 96-121). The Company provided cost comparisons for these three water supply options (Exh. HO-RR-71(supp.)).[163]

With respect to the groundwater well option, the Company indicated that the on-site aquifer would be inadequate to meet the water supply needs of the proposed project (Exh. BP-FS-2, at 4-13 to 4-16; Tr. 12, at 120-121). The Company stated, however, that the water supply needs of the proposed facility could be met by off-site aquifers in the region (Tr. 12, at 120-121). The Company argued that its preferred option offered several advantages over the groundwater well option (Exh. HO-RR-71(supp.)). First, the Company indicated that it had made a commitment to use the Agawam municipal system for the proposed facility, and that the Town's revenues from the water sales would offset earlier capital investments made to upgrade the Agawam municipal system (id.). The Company also asserted that, in contrast to the groundwater well and the Connecticut River options, the preferred option would not require permitting and would therefore avoid the delays and associated increased costs which might be triggered by permitting (id.).

The Company asserted that the Connecticut River option would be technically feasible but environmentally and economically inferior to the preferred option (Exh. BP-FS-2, at 4-23). In support of its assertion, the Company noted that the Connecticut River option would require the construction of a dedicated water main from the proposed facility to a dedicated intake structure at the bank of the river (id. at 4-19). The Company indicated that it could identify only one feasible site for the intake structure, a parcel of Town land located immediately south of the Bondi's Island Wastewater Treatment Facility ("Bondi's Island"), owned by the City of Springfield (id. at 4-17; Exh. HO-RR-69(supp.); Tr. 12, at 100-117). The Company identified two potential routes, one 4.78 miles and the other 5.35 miles in length, for a water main linking the intake structure and the proposed facility (Exh. BP-FS-2,

163 The Company indicated that over twenty years, the projected costs of the preferred and groundwater well options would not be significantly different (Exh. HO-RR-71 (supp.)). The Company asserted that the lower capital costs of the preferred option would enable the Company to hold down power costs during the proposed facility's early years of operation (id.). See Section III.B.3, below.

at 4-19). The Company noted, however, that significant construction-related impacts were associated with each of the routes (id. at 4-20). The Company also indicated that, even with a Connecticut River intake and connecting water main in place, it would likely still rely on the Agawam municipal system to meet potable needs and to supply water to the HRSG (Tr. 12, at 112).

(B) Water-Related Discharges

The Company indicated that maximum wastewater discharge from the proposed facility would be .238 mgd,[164] and that wastewater would flow from the proposed project at the primary site via a new 100-foot interconnect to an existing on-site main, which is part of the Agawam municipal wastewater treatment system (Exh. BP-1B at 7-65; Tr. 12, at 29-30). The Company indicated that the Town's municipal wastewater treatment system discharged to Bondi's Island (Exh. BP-FS-2, at 3-76). The Company provided information with respect to the capacity of Bondi's Island for the years 1996 through 2020 and to Agawam's contractual allowances for wastewater discharge (id.).[165] The Company asserted that the Agawam municipal wastewater treatment system and Bondi's Island would have sufficient capacity to accommodate discharge from the proposed facility (Exh. BP-1B at 7-65 to 7-67; Tr. 12, at 156-159). The Company further asserted that the design of the proposed facility would ensure minimal impacts to the Agawam municipal wastewater treatment system, other municipal users, and the Connecticut River (Exhs. BP-FS-2, at 3-76; HO-E-34).

The Company described its plans to limit the stormwater impacts of the proposed facility on wetlands and surface water resources (Exhs. BP-1B at 7-57 to 7-58; BP-FS-2, at

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164 The Company asserted that with gas-fired generation, on average, the proposed facility would generate .187 mgd of wastewater (Exh. BP-1B at 7-66).

165 The Company stated that Agawam had a contractual allowance for an average daily flow of 6.1 mgd and a peak flow of 15.4 mgd (Exh. BP-FS-2, at 3-76). The Company indicated that current total system flows averaged less than 3 mgd (id.; Tr. 12, 158-160).

3-50, 3-64; HO-E-1(att.) at 2-12 to 2-15). The Company also submitted modifications to its plans to reflect the Agawam Conservation Commission's Order of Conditions ("Order of Conditions") for the proposed facility, as well as comments from state agencies in response to the Company's DEIR (Exhs. HO-E-1(att.) at 2-12 to 2-15; BP-FS-5). The Company indicated that, as part of its plans to control stormwater impacts to surface waters, it would provide an on-site stormwater detention pond designed for a 100-year, 24-hour storm (Exh. BP-FS-2, at 3-64, 3-76). The Company noted that, in accordance with the Order of Conditions, the Company would construct a 100-foot discharge channel beyond the end of the discharge pipe from the stormwater detention pond, and that the pipe and channel would extend through the 100-foot buffer zone to the edge of the on-site wetland resource area in the southwestern portion of the primary site (Exh. HO-E-1(att.)).

(C) Construction Impacts

The Company also evaluated potential impacts of construction of the proposed facility at the primary site on water resources, including wetlands (Exh. BP-1B at 7-49 to 7-52). The Company asserted that the proposed facility would be sited outside all on-site wetlands and buffer zones (Company Brief at 84). The Company stated that none of the approximately 2.75 acres of on-site wetlands at the primary site would be disturbed by the footprint of the proposed facility (Exhs. BP-1B at 7-51; BP-FS-2, at 3-45).

With respect to the construction of a water supply interconnect for the proposed project, the Company indicated that a new main from the proposed facility to the Agawam municipal system at Franklin Street Extension would be built entirely within the roadway or shoulder of the plant access road, Moylan Lane, Shoemaker Lane and Silver Street to avoid overland water resource and wetlands impacts (Exh. BP-FS-2, at 3-73). The Company also stated that interconnection with existing on-site electric transmission and sewer lines would not affect wetland resources or associated buffer zones (Exh. HO-S-22(att.)).

With respect to the Tennessee gas interconnect required for the proposed facility at the primary site,[166] the Company stated that the on-site portion of the gas interconnect would cross a 300-foot stretch of buffer zone associated with a wetland area in the southwest portion of the Agawam site (Exh. BP-FS-2, at 3-53). The Company indicated that temporary impacts of construction within a 30-foot swath of wetland buffer along the on-site gas interconnect route, totalling approximately 9,000 square feet, would be limited by the use of all appropriate soil erosion and sedimentation control measures (id.; Exh. HO-E-29; Tr. 12, at 13). The Company stated that Tennessee also would use all appropriate soil erosion and sedimentation control measures to limit any impacts along the 900 to 1,000 linear feet of buffer zone along the route of the off-site portion of the gas interconnect (Exh. BP-FS-2, at 3-53; Tr. 12, at 13-14). The Company asserted that its proposed route for off-site construction of the Tennessee gas pipeline from the proposed facility to the Tennessee Gas mainline and compressor station would minimize impacts to wetlands and associated buffer zones (Tr. 12, at 8-10).

In conclusion, the Company asserted that the proposed facility at the primary site would minimize environmental impacts with respect to all water resources, including wetlands, waterways and groundwater (Exhs. BP-1B at 7-49; Company Brief at 86).

ii. Alternative Site

The Company also evaluated the impacts of the proposed facility on water resources at the alternative site (Exh. BP-1B at 8-8 to 8-17). The Company asserted that the construction and operation of the proposed facility at the alternative site would minimize environmental impacts with respect to water resources, including wetlands, waterways and groundwater (id. at 8-8).

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166 The Company indicated that Tennessee, rather than the Company, would construct and operate the gas interconnect from the Tennessee mainline to the proposed facility (Tr. 12, at 8-10).

The Company stated that it had identified five water supply options for the alternative site (id. at 8-9). The Company indicated that one option would be to access water from the City of Springfield via its water main at the Southwick/Westfield town line (id.). The Company stated that impacts associated with use of the City of Springfield's water supply would be the same at the alternative site as at the primary site (id.). The Company stated that the four remaining water supply options for the alternative site all would draw water from the same local aquifer, and therefore would have uniform water supply impacts except in respect to water main routing (id.).[167]

BPD indicated that wastewater from the proposed project at the alternative site would be discharged to a planned new Southwick municipal system, which in turn would discharge to the Westfield municipal system (id. at 8-13).[168] The Company stated that the wastewater interconnect with the planned Southwick municipal sewer system would be routed via roadbed to avoid wetland and buffer zone impacts (Tr. 12, at 33).[169] The Company proposed to minimize stormwater impacts at the alternative site with a stormwater detention pond similar to that at the primary site (Exh. BP-1B at 8-14).

The Company also demonstrated that the proposed facility at the alternative site would be constructed outside all wetlands, and that impacts to wetlands would be limited to temporary impacts associated with construction of the electric and gas interconnects (id. at

167 The four alternatives include: using the Southwick municipal water supply; developing a private well; using the Westfield water supply; or using Town of West Springfield wells located in Southwick (Exh. BP-1B at 8-9).

168 The Company stated that the Town of Southwick planned to have a new sewer system in operation prior to 1999 (Exh. BP-1B at 8-9). The Company indicated that, with the planned Southwick municipal sewer system in place, wastewater from the proposed facility would travel through an on-site interconnect to the Town of Southwick's municipal sewer system, to be discharged to the Westfield Great Brook Pumping Station (Exh. BP-1B at 8-9 to 8-10).

169 The Company noted that the wastewater interconnect would be approximately 25 times longer at the alternative site than at the primary site (Tr. 12, at 30-31).

8-10 to 8-12).[170] The Company noted that two Flood Zone areas, an on-site area designated Flood Zone B and an off-site area designated Flood Zone A, pose an additional design complication at the alternative site (id. at 8-11; Exh. HO-RR-64; Tr. 12, at 19).[171]

iii. Analysis of Impacts

The Company has demonstrated that its project design incorporates a number of measures to reduce water use at the proposed facility at either the primary or the alternative site. However, the record indicates that dry cooling would significantly reduce the water supply needs of the proposed project. It would also produce a significant increase in noise impacts, and decrease in the efficiency of the proposed facility. The Siting Board will review the balance between water use, noise impacts, and cost in Section III.B.4, below.

With respect to water supply options, the Company has demonstrated that the Springfield municipal system is likely to provide an adequate water supply for the proposed project at either the primary or the alternative site. The Company has further demonstrated that the infrastructure necessary to deliver water to the proposed facility from the Springfield

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170 The Company noted that the gas interconnect would cross approximately 9,000 feet of buffer zone, but would be placed in the shoulder and pavement of roadways to limit pipeline crossings to no more than 20 feet of wetlands and 400 feet of buffer area (Exhs. BP-1B at 8-10; HO-RR-65; Tr. 12, at 15-17). The Company maintained that the gas interconnect would be of comparable length and have comparable wetlands and buffer zone impacts at the primary and alternative sites (Exh. BP-1B at 8-12; Tr. 12, at 17). The Company stated that, to minimize impacts to wetlands from the one-mile overhead portions of the electric interconnect for the alternative site, above-ground transmission structures would be placed outside any wetland areas, and the associated transmission line would span wetlands overhead (Exh. BP-1A at 2-7). The Company also indicated that portions of the electric interconnect would be constructed in the railbed of an abandoned railroad right-of-way ("ROW") (Tr. 12, at 26-27).

171 Flood Zone A and Flood Zone B are Federal Emergency Management Act designations which identify areas vulnerable to a 100-year flood (Flood Zone A), and a 100- to 500-year flood (Flood Zone B) (Exh. BP-1B at 8-11). The flood zone designations at the alternative site denote areas of potential flooding associated with Slab Brook in Southwick (id.; Tr. 12, at 19).

municipal system, with the exception of water supply interconnects, is already in place at both the primary and alternative sites. The Siting Board notes, however, that this water supply option would entail significant consumption of potable water for process uses. Although demands on the City of Springfield's water supply have declined in recent years, the record suggests that the system will face increased demand between 1995 and 2010.

In addition, the Siting Board notes that withdrawal of water from Cobble Mountain may make less water available for the Little River below Cobble Mountain. While the record indicates that flows in the Little River below Cobble Mountain have been intermittent during periods of low-flow since 1931, withdrawals for the proposed project could theoretically lengthen seasonal no-flow periods and reduce spillage over the dam at Cobble Mountain during "shoulder periods."

BPD has argued that management of Cobble Mountain, including the quantity of flow released in the Little River below Cobble Mountain, is a concern within the jurisdiction of the City of Springfield and not a matter over which the Company has control. While the Siting Board recognizes that BPD would be one of the many water system users in several communities which obtain water from Springfield, we also note the considerable quantities of high quality water which the proposed project would demand.

The Siting Board notes that the Certificate on BPD's FEIR recommended that the responsible officials determine whether the proposed project would warrant an increase in the registered maximum withdrawal of the Springfield system from Cobble Mountain. Further, MDEP has recommended that BPD have in place a long-term emergency water use plan, which would incorporate alternative sources to relieve the municipal supply in the event of excessive drought conditions.

The Siting Board recognizes that the City of Springfield is responsible for maintaining the Springfield municipal system, including Cobble Mountain, and for any impacts on other resources, such as the Little River below the dam at Cobble Mountain, which may be affected by management of the Springfield municipal system. However, in light of the considerable quantities of high quality water which the proposed project would demand, and the projections for increases in overall demand on the Springfield system, the Siting Board directs the Company to work in conjunction with the City of Springfield to identify and to implement, as appropriate, measures to ensure the long-term ability of the Springfield municipal system, including Cobble Mountain, to supply BPD and other customers. Effective measures could include further development of a backup water supply for BPD, such as groundwater wells, but also could include pursuit of programs to conserve water resources used by BPD or used elsewhere in the service areas supplied by Springfield. The extent to which such measures would be necessary may depend on the outcome of the assessment, recommended in the Certificate on BPD's FEIR, as to whether an increase in registered withdrawals from Cobble Mountain is warranted, and more generally, may depend on whether system water demand increases as projected between 1995 and 2010.[172] The Siting Board finds that, with the implementation of this condition, the water supply impacts of the Company's preferred option on the Springfield municipal system would be acceptable.

BPD has analyzed two other sets of water supply options: the Connecticut River option, and the groundwater well option. The Connecticut River option would reduce consumption of potable water and possible impacts on the Little River. However, the feasibility of this option is greatly constrained by the lack of available sites for construction of a water intake pipe and pumphouse along the Connecticut River. The Company also has shown that the impacts of constructing an approximately 5-mile water transmission line from the intake pipe on the Connecticut River to the primary site would be substantial, and that permitting would present significant difficulties. Consequently the Siting Board finds that the preferred option is preferable to the Connecticut River option.

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172 The Siting Board notes that such measures to ensure the long-term ability of the Springfield municipal system to supply water would allow the City of Springfield to better maintain the quality of other affected resources, including the Little River below the dam at Cobble Mountain.

The Company also has considered groundwater well options at both the primary and alternative sites.[173] Because the Company did not provide specific information as to the likely well locations and interconnection routes, it has not established that the water supply impacts of these options would match or exceed those of the preferred option. However, the Siting Board notes that well withdrawals sufficient to meet BPD's needs could conflict with other water uses, affect nearby surface waters or wetlands, or require lengthy interconnection routes that affect wetland or buffer zone areas. In addition, groundwater well options would involve additional permitting requirements, likely including water withdrawal permits. From the standpoint of limiting environmental impacts, the Company's preferred option, relying on the Springfield municipal system, offers a number of potential advantages over the other considered options, including the fact that a supply infrastructure is in place and that the watershed and water volume available to recharge Cobble Mountain are considerable. Thus, any advantage of groundwater well options over the preferred option with respect to water supply and water resource impacts likely would be limited.

The record shows, however, that (1) BPD's reliance on its preferred water supply will result in consumption of large quantities of high-quality water from the Springfield municipal system and may contribute to impacts on associated water resources such as the Little River, and (2) the identified alternative of a groundwater well option might avoid such impacts. The record also shows that the water supply needs of the proposed facility would be significantly reduced with the use of dry cooling. Consequently, the Siting Board finds that the Company has not established that its preferred option results in a minimum environmental impact with respect to water supply and related water resources. The Siting Board will review the balance between water supply impacts, land use impacts, and cost in Section III.B.4, below.

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173 These include BPD-developed wells in aquifer areas in the primary site vicinity, and BPD-developed or municipal wells in the large aquifer proximate to the alternative site.

The Company has demonstrated that impacts to all water resources resulting from wastewater and stormwater discharge from the proposed project would be minimized at the primary site. The Company also has demonstrated that wetlands impacts associated with all interconnects would be minimized at the primary site for the proposed project as designed. Accordingly, the Siting Board finds that impacts from water-related discharges and construction-related impacts of the proposed facility at the primary site would be minimized.

Finally, in comparing the primary and alternative sites, the Siting Board finds that impacts of the proposed facility with respect to water supply and related water resources would be comparable at the primary and alternative sites. The Siting Board also finds that, if Southwick's municipal wastewater discharge system is constructed as planned, the impacts from water-related discharges at the primary site would be comparable to those at the alternative site. However, the fact that the Southwick municipal wastewater system has yet to be constructed introduces an element of uncertainty at the alternative site with respect to wastewater discharge which is not present at the primary site.

With respect to construction impacts to wetlands, the Siting Board notes that such impacts at both sites would be temporary and limited by undertaking construction in roadbeds and existing ROWs. However, construction impacts to wetlands would be slightly greater at the alternative site than at the primary site, primarily due to the longer length of interconnects and the greater number of wetlands and buffer zone areas to be crossed by interconnects off-site. Consequently, the Siting Board finds that construction impacts at the primary site would be slightly preferable to those at the alternative site.

Accordingly, the Siting Board finds that, on balance, the primary site would be slightly preferable to the alternative site with respect to water-related impacts.

c. Visual Impacts

The Company submitted a comprehensive evaluation of potential visual impacts of the proposed facility at the primary and alternative sites (Exh. BP-1B at 7-93 to 7-107, 8-48 to 8-52). As part of its evaluation at each site, the Company conducted a viewshed analysis of the surrounding area (id. at 7-95, 8-48 to 8-49). For each viewshed analysis, the

Company identified and mapped areas within 1.5 to 2.0 miles of the proposed sites from which the stack of the facility might be visible, assuming a 175-foot stack (id.). From areas where the stack was likely to be visible, the Company selected visual receptor locations, 14 for the Agawam site and 10 for the Southwick site, on the basis of land use, proximity to site, and severity of impact (id.).[174] The Company chose a season without deciduous foliage to take photographs from the identified receptor locations looking toward the proposed facility. The Company then generated a computer-developed view of the facility and stack as they would appear from a given receptor and superimposed the view on the associated photograph (id. at 7-95 to 7-97; 8-48 to 8-49).

The Company also conducted a plume analysis to assess the conditions and frequency under which a plume was likely to emanate from the main stack or cooling tower of the proposed facility, and the distance from the proposed facility to which a visible plume would likely extend (id. at 7-102 to 7-106; Tr. 10, at 107-112; Tr. 11, at 16-18). Based on its analysis, the Company asserted that, over the course of a year, during daylight hours, plumes from the main stack with lengths of 100 meters or more would be visible very infrequently and that plumes from the cooling tower of 100 meters or more would be visible even less frequently (Exh. BP-1B at 7-104 to 7-106; Company Brief at 112).[175] The Company

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[174] The Company indicated that the visual receptor locations for each site also included locations from which the stack would not be visible in order to verify the computer generated analysis and to present a balanced assessment of the overall visual impact (Exh. BP-1B at 7-95, 8-48 to 8-49).

[175] The Company's analysis indicated that, over the course of a year, plumes from the main stack with downwind lengths of 100 meters or more would be visible 4 percent of daytime hours, plumes with lengths of 50-100 meters would be visible 27 percent of daytime hours, and that plume length downwind and height above stack top would be approximately equal (Exh. BP-1B at 7-104). With respect to plumes from the cooling tower, the Company indicated that plumes with lengths of 100 meters or more would be visible 1.2 percent of daytime hours, whereas plumes with lengths of 50-100 meters would be visible 12.3 percent of daytime hours (id. at 7-105). The Company's analysis further indicated that, for the measured lengths, plume height above the cooling tower would be approximately half of plume length downwind (id.)

indicated that including nighttime hours visible plume calculations would increase annual plume visibility percentages, but asserted that a condensed plume is normally not noticeable at night due to the lack of illumination (Exh. HO-RR-76; Tr. 10, at 108-112; Tr. 13, at 25).[176] In addition, the Company stated that its plume analysis showed that fog and/or precipitation would be present most of the time that main stack and cooling tower plumes of 100 meters or longer were present, reducing further the visibility of the plume (Exh. BP-1B at 7-106).

i. Primary Site

Based on its analysis of computer-developed views from 14 selected receptor locations, the Company asserted that visual impacts of the proposed facility at the primary site would be minimal (Company Brief at 111). The Company stated that, according to its visual impacts analysis, the stack or other structural elements of the proposed facility would be visible from only 23 percent of the viewshed area and that, over most of the impacted area, current views would not be significantly affected (Exhs. BP-1B at 7-98; HO-RR-60(rev.)).

The Company indicated that views of both facility buildings and stack would be predominant from a receptor at Losito Road and Shoemaker Lane to the west of the proposed facility site (Exh. BP-1B at 7-99). The Company added that views from receptors to the east and south, including points on or near Suffield Street and the southern portion of Shoemaker

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176 The Company indicated that a 50-meter-long plume from the cooling tower of the proposed facility would likely be visible 65 percent of the year, including night hours, but only about 13 percent of the year excluding night hours (Exh. HO-RR-76). The Company further indicated that a plume of 100 meters' length would likely be visible eight percent of the year, including night hours, but only one percent of the year excluding night hours (id.).

Lane, as well as to the northwest, in the vicinity of the Saint Anne Golf Course, would be limited to the top of the stack (id. at 7-99 to 7-100).[177]

The Company stated that it had prepared a landscaping plan at the primary site which would further reduce visual impacts resulting from line-of-sight views of the proposed facility from immediately surrounding areas, particularly to the west and east (id. at 7-101 to 7-107; Exh. HO-E-1, at 2-1, fig. 2.1-1). BPD indicated that it would provide additional shrubs or trees to soften the view of the facility from off-site locations, if requested by local residents (Tr. 13, at 91).[178]

Based on its plume analysis, the Company stated that visible plumes of 100 meters or more from the main stack or the cooling tower of the proposed facility would occur infrequently at the Agawam site (Exh. BP-FS-2, at 3-154 to 3-155). In addition, the Company stated that its plume analysis demonstrated that fog and/or precipitation would also be present most of the time that main stack and cooling tower plumes of 100 meters or more were present, further reducing the visibility of the plume (id. at 3-155). The Company asserted that nothing in the record supports the proposition that plumes generally cause adverse visual impacts, and that, absent such evidence of effect, the plume conditions projected for the proposed facility -- infrequently-occurring visible plumes often coincident with fog or precipitation -- are consistent with a finding that visual impacts at the Agawam site would be minimized (Company Brief at 112-113). The Company further asserted that the infrequent presence of a plume from the stack and cooling tower will have no negative visual impacts (id. at 113).

177 The Company's analysis indicated that the presence of intervening wooded areas would soften facility views from most vantage points (Exh. BP-1B at 7-98 to 7-100). Principal exceptions include locations near: (1) Shoemaker Lane, west of the site; (2) Silver Street at Almgren Drive, north of the site; and (3) the end of Industrial Lane, southeast of the site (id. at 7-98 to 7-100; Exh. BP-1B, fig. 7.7.2).

178 BPD stated that it had discussed providing trees and shrubs with the Agawam Planning Board and had made a commitment to do so (Tr. 13, at 91).

Country Estates contended that the proposed facility would not be compatible with the existing visual environment at the Agawam site (Country Estates Brief at 4). In support of its contention, Country Estates cited the height limit of 40 feet for structures in Agawam as defined by Agawam's Zoning By-laws and noted that the height limit would be exceeded by a 175-foot stack or even a 125-foot stack constructed as part of the proposed facility (id.).[179] Country Estates also noted that its property, i.e., the Country Estates Nursing Home building and associated landscaping, was included in the Company's reference to intervening development that would partially obscure the proposed facility from view at the receptor location on Suffield Street just south of Adams Street (receptor location A-4) (id. at 4 to 5; Exh. BP-1B at 7-97, fig. 7.7.6). Country Estates asserted that while the view of a traveller along Suffield Street would be partially obscured by the Country Estates Nursing Home, Country Estates would have a direct and unobscured view, not only of the stack of the proposed facility, but of the plumes emanating from the stack and the cooling tower, including plumes of less than 100 meters' height (Country Estates Brief at 4 to 6).[180]

ii. Alternative Site

Based on its computer-developed analysis of views from 10 selected receptor locations, the Company asserted that visual impacts of the proposed facility at the alternative site would be minimal (Exh. BP-1B at 8-48 to 8-49). The Company noted that, according to its visual impacts analysis, the stack or other structural elements of the proposed facility

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179 Both Country Estates and CCBA cited statements regarding the generally rural character of the area surrounding the primary site contained in the decision of the Agawam ZBA denying the Company's request for a special permit (Country Estates Brief at 4; CCBA Brief at 4). See also Exh. HO-RR-62.

180 BPD asserted that, based on elevation differences and intervening wooded area, Country Estates Nursing Home likely would have no view of the proposed facility other than its plume (Tr. 13, at 86). The Company's computer-developed view of the proposed facility from the nursing home location, however, suggests that at least a partial view of the stack will be visible from Country Estates (Exh. BP-1B at fig. 7.7.6).

would be visible from only seven percent of the viewshed area and that, over most of the impacted area, current views would not be significantly affected (id. at 8-48 to 8-52, fig. 8.7.1; Exh. HO-RR-60(rev.)). The Company also indicated that due to the terrain of the Southwick site and the heavily wooded nature of surrounding areas, substantially fewer and smaller portions of the neighboring community would be afforded views of the proposed facility at the alternative site than at the Agawam site (Exh. BP-1B at 8-52). The Company asserted that visual impacts of the plume at the primary and alternative sites would be comparable (id. at 8-48). The Company further asserted that the alternative site is preferable to the primary site with respect to visual impacts (Company Brief at 114).

iii. Analysis

The record demonstrates that the proposed facility at the primary site is in an area of mixed use (see Section III.B.2.h, below) and that natural and planted vegetative screening as well as existing development would in most sensitive cases soften, if not obscure, a view of the proposed facility and its cooling tower and stack. The record clearly demonstrates that the proposed facility will have visual impacts at the receptor location at Losito Road and Shoemaker Lane, and along portions of Shoemaker Lane west of the site. In addition, Country Estates may have at least a partial view not only of the proposed facility, but of plumes from the stack and cooling tower, when they are present.

With respect to plumes from either the stack or cooling tower of the proposed facility, the Company's analysis demonstrates that visible plumes of 100 meters will occur only a small percentage of daytime hours. The record also demonstrates, however, that smaller plumes from the stack and the cooling tower are likely to be visible with considerably greater frequency during daytime hours. While the Siting Board agrees with the Company that nothing on the record shows the predicted plumes to be harmful, the record also suggests that the visual impact of such plumes may warrant mitigation at specific sensitive receptors.

In a previous review, the Siting Board has required a generating facility proponent to provide selective tree plantings in residential areas up to one-half mile from the proposed stack location to help ensure no more than intermittent visibility of the stack and other facility structures in such areas. NEA Decision, 16 DOMSC at 408-409. Here, in addition to trees and/or shrubs provided as part of its landscaping plan and its seedling distribution program, the Company has expressed a willingness to provide shrubs or trees to soften the view of the facility from off-site locations, if so requested by local residents. Accordingly, consistent with a past review and the Company's stated offer, and in order to ensure that visual impacts are minimized, the Siting Board directs the Company to provide reasonable off-site shrub and tree plantings to help screen the proposed facility from roadways and properties on or near the intersection of Losito Road and Shoemaker Lane, and on or near Suffield Street and the southern portion of Shoemaker Lane, and at other locations within one mile of the proposed facility, as may be requested by property owners or appropriate municipal officials. In implementing its plan for off-site shrub and tree planting, BPD: (1) shall provide shrub and tree plantings on private property only with the permission of the property owner, and along public ways only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Agawam and to all affected property owners prior to commencement of construction; (3) may limit requests from local residents and town officials for shrub and tree plantings to no less than six months after initial operation of the plant; (4) shall complete all such requested plantings within one year after commencement of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement of such plantings as necessary to ensure that healthy plantings become established. In addition, the Siting Board encourages BPD to work with affected local residents, entities and institutions to develop other reasonable forms of cost-effective visual mitigation.

Accordingly, the Siting Board finds that, with the implementation of the forementioned condition, and with a 125-foot stack, the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts. The Siting Board notes that the visual impacts of a 167.5-foot stack would be considerably greater than those of a 125 foot stack. The Siting Board will review the balance between the visual impacts of a 167.5 foot and the air impacts of a 125-foot stack in Section III.B.4, below.

The record demonstrates that the proposed facility at the alternative site is in an area of mixed use and that natural and planted vegetative screening as well as the terrain of the surrounding area will in most cases, and in all sensitive cases soften, if not obscure, a view of the proposed facility and its cooling tower, stack and plumes. Accordingly, the Siting Board finds that the alternative site would be preferable to the primary site with respect to visual impacts.

d. Noise

i. Primary Site

BPD asserted that the noise generated by operation of the proposed facility at the primary site would not adversely affect residences or businesses, and would be minimized consistent with Siting Board standards (Company Brief at 114-117). BPD further asserted that noise from operation of the proposed facility (1) would produce noise increases at nearby residences within the applicable MDEP ten-dBA limit, while retaining a significantly quieter residential noise environment relative to that in other generating facilities cases reviewed by the Siting Board and (2) would cause no adverse impacts at the nearest property lines based on existing non-residential land uses and zoning and applicable federal guidelines for non-residential exposure (id. at 116-117). BPD asserted that worst-case construction noise levels would be intermittent and temporary, and comparable to the current daytime noise environment in which heavy truck traffic is a common occurrence (Exh. BP-1B at 7-116).

BPD stated that, to be noticeable to people, an increase in average noise level must be greater than three dBA (Tr. 7, at 45). The Company indicated that there are various measures of noise, and noted that the MDEP guideline limiting noise increases to ten dBA is based on a relatively quiet measure of ambient noise that essentially is the residual sound level observed when there are no louder, transient sounds, specifically that level of noise that is exceeded 90 percent of the time ("L_{90}") (Exh. BP-DK-3, at 5, 9). The Company stated that the MDEP ten-dBA limit is applicable at both the nearest residences and nearest property lines, but asserted that MDEP has taken a common sense approach allowing higher increases at non-residential property lines of generating facilities -- if, for example, nighttime exposure would not be a factor because people would not be present and daytime exposure would not exceed non-residential safety guidelines (id. at 9; Brief at 117, citing, Tr. 7, at 26-27).[181]

In support of its position that the proposed facility would adequately minimize noise impacts, BPD provided analyses of ambient background noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. HO-E-26, at 6-1 to 6-15; BP-DK-3).[182] To establish existing background noise levels, BPD provided measurements of daytime and nighttime noise for each of nine receptors, including five residential receptors located at distances of 1,300 to 3,400 feet from the proposed stack, and four property line receptors located at distances of 360 to 590 feet from the proposed stack (Exh. HO-E-26, at 6-1 to 6-10). BPD stated that the principal sources of ambient noise include mechanical equipment at nearby industrial and commercial buildings, traffic on nearby roadways, and distant transportation at night (Exh. BP-1B at 7-113 to 7-114).

To determine noise impacts from operation of the proposed facility, BPD provided estimates of combined facility and background noise by receptor for daytime and nighttime periods (Exh. BP-DK-3, at 16-40). BPD's analysis indicates that, with facility operation, daytime L_{90} levels would increase by zero to two dBA at residential receptors and by six to

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181 BPD indicated that Federal Environmental Protection Agency ("EPA") recommends, as a guideline for avoiding hearing loss, a worker exposure limit of 75 dBA average noise over eight hours, assuming exposure for the remaining 16 hours is significantly less (Exh. HO-E-26, App. B at 11).

182 Measurements of background noise and calculations of facility noise and combined noise are based on a logarithmic scale (Exh. BP-DK-3, at 5). Combined facility and background noise at a receptor often is larger than each of the components -- the calculated facility noise contribution and the background noise -- considered separately (id. at 5-7, 39). For a receptor where the calculated facility noise contribution is significantly louder or quieter than the background noise, however, the facility noise may mask or be masked by the background noise, resulting in a combined facility and background noise that equals or barely exceeds the louder of the separate components. (id.)

24 dBA at property line receptors (id. at 39).[183] The analysis further indicates that, with facility operation, nighttime L_{90} levels would increase by two to eight dBA at residential receptors[184] and by 20 to 34 dBA at property line receptors (id.; Tr. 7, at 21-22).

BPD maintained that the estimated L_{90} increases at property line receptors in excess of the MDEP ten-dBA limit would not be a concern, because the abutting land at all four such receptors is not currently residential and is not zoned to allow residential use (Exh. HO-RR-33; Tr. 7, at 22-23).[185] With respect to the two receptors at which daytime noise increases would be in excess of ten dBA, the Company indicated that the northeast property line abuts land owned by WMECo that is traversed by transmission lines but otherwise vacant,[186] and the southeast property line abuts existing commercial/industrial parcels at the end of Industrial Lane, a cul-de-sac extending from Shoemaker Lane

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183 Two receptors show increases in excess of the MDEP ten-dBA limit, including the northeast property line receptor, which would increase by 24 dBA to an ambient level of 67 dBA, and the southeast property line receptor, which would increase by 14 dBA to an ambient level of 61 dBA (Exh. BP-DK-3, at 39).

184 Three of the residential receptors show nighttime L_{90} increases approaching the ten-dBA limit, including: (1) an increase from 33 to 41 dBA at Moylan Lane, near Shoemaker Lane west of the site; (2) an increase from 31 dBA to 38 dBA at Shoemaker Lane south of the site; and (3) an increase from 31 dBA to 38 dBA at Doane Avenue north of the site (Exh. BP-DK-3, at 39).

185 The Company provided information indicating that existing zoning would allow agricultural use, residential use for a previously recorded subdivision or lot, and a rest home with receipt of a Special Permit from the ZBA (Exhs. HO-RR-33; HO-E-48). Regarding residential use, however, the Company noted that no subdivision plan nor individual lot is recorded for such use in the undeveloped area abutting the proposed site. (Exh. HO-RR-33) See also, Section III.B.2.h, below.

186 The transmission lines on WMECo's land are located to the north, northeast and east of the location of the nearest proposed facility structure, the cooling tower, at distances of approximately 800 to 1,200 feet (Exhs. BP-2; HO-S-22).

(Exh. HO-E-26, at 6-13; Tr. 7, at 28-29, 34).[187,188] BPD noted that the combined background and proposed facility noise levels during the day, 67 dBA and 61 dBA at the northeast and southeast property lines respectively, would be below an eight-hour work day average of 75 dBA -- the limit recommended by EPA to protect people's hearing (Exh. BP-DK-3, at 39-40). BPD added that the noise contributions from the proposed facility, which also are 67 dBA and 61 dBA at the northeast and southeast property lines respectively, would drop to 55 dBA at points within the abutting parcels 450-750 feet beyond the property line receptors (Tr. 7, at 29-36).[189]

BPD further evaluated its estimates of facility and background noise at residential receptors based on comparisons with (1) similar estimates reviewed by the Siting Board in other generating facility cases, and (2) EPA's recommendation of a maximum day-night noise level ("L_{dn}") of 55 dBA in residential areas to avoid undue activity interference, complaints or annoyance (id. at 92-93; Exh. BP-DK-3, at 3-4, 6, 11; Tr. 7, at 92-93).[190]

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187 BPD stated that the nearest parcel on the west side of Industrial Lane, adjacent to the receptor, is used for a heliport, and the nearest parcel on the east side of Industrial Lane is used for a foundry (Tr. 7, at 28).

188 Although the immediately abutting parcels contain existing commercial or industrial uses or WMECo transmission lines, maps provided by BPD indicate that undeveloped land extends for a distance of a half-mile or more, to the southeast, east and northeast from the locations of the eastern most proposed facility structures and includes parcels owned by a number of other landowners as well as WMECo (Exhs. BP-2; HO-S-6(att. S-6b)).

189 The expected noise contribution from the proposed facility would be 55 dBA at points within the WMECo property 750 feet beyond the northeast property line receptor, and at points within the Industrial Lane area 450 feet beyond the southeast property line receptor, including a point on Industrial Lane located approximately 1,300 feet north of Shoemaker Lane (Tr. 7, at 30-36). The expected noise contribution of 55 dBA at such points would be 12 dBA above the existing daytime background L_{90} level at the northeast property line receptor, and eight dBA above that at the southeast property line receptor (Exh. BP-DK-3, at 39).

190 BPD indicated that the EPA L_{dn} indicator reflects the average sound level over a
(continued...)

BPD's witness, Mr. Keast, testified that the estimated nighttime L_{90} at the nearest residential receptor with operation of the proposed facility would be 41 dBA, considerably lower than corresponding worst-case levels for four earlier gas-fired generating facilities approved by the Siting Board (Tr. 7, at 92-93).[191] BPD also stated that the maximum L_{dn} contribution from the proposed facility at a residential receptor would be 47 dBA, well below the EPA 55-dBA guideline (Exh. BP-DK-3, at 40).[192]

With respect to construction noise, the Company provided estimates of long-term average noise by construction phase at the nearest residence, located near Moylan and Shoemaker Lanes 1,300 feet from the southwest property line (id. at 12-14). The Company estimated average noise impacts of 61 dBA during the excavation phase and the finishing

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[190](...continued)
24-hour period with a ten-dBA penalty factor added for a nine-hour nighttime period, to reflect the higher sensitivity to noise of people in their homes at night (Exh. BP-DK-3, at 6). BPD added that, for a steady noise such as that from a generating facility, the nighttime penalty factor results in an L_{dn} that is 6.4 dBA greater than a 24-hour average or other equivalent noise measure without the penalty (Tr. 7, at 55).

191 Mr. Keast cited worst-case nighttime L_{90} levels at residential receptors ranging from 48 to 51 dBA in three reviews of independent power producer projects (Tr. 7, at 92-93). See Enron Decision, 22 DOMSC at 208; MASSPOWER Decision, 20 DOMSC at 390; NEA Decision, 16 DOMSC at 401-402. He added that the worst-case nighttime L_{90} level for the Altresco-Pittsfield project, also approved by the Siting Board, was estimated to be 48 dBA (id.).

192 The Company did not provide estimates of combined facility and background L_{dn} levels; however, the Company did provide hourly measurements of average noise over a 24-hour period for a receptor at Moylan Lane, where it intersects with Shoemaker Lane west of the site, and a receptor at Shoemaker Lane south of the site (Exh. BP-1B, fig. 7.8.2 and 7.8.3). BPD's measurements indicate hourly average noise for late evening and nighttime periods ranging from approximately 40 to 55 dBA at both receptors, and hourly average noise for the remainder of the day ranging from approximately 50 to 58 dBA at both receptors (id.). The Siting Board notes that, if the ten-dBA penalty factor for late evening and nighttime periods is incorporated, the Company's measurements indicate an existing ambient L_{dn} of close to the 55 dBA guideline at both receptors (id.).

phase, with lesser impacts ranging from 50 to 57 dBA during the remainder of the approximately one and one-half year construction period (id.; Exh. HO-V-8(att.)). BPD added that facility construction would require ten to 70 construction vehicle round trips per day as well as additional automobile traffic, which would result in noticeable noise at nearby residential locations on Shoemaker Lane (Exh. BP-DK-3, at 15). The Company indicated that construction normally would be limited to the hours of 7:30 a.m. to 4:00 p.m., Monday through Friday (Exh. BP-1A at 7-129).

The Company asserted that its proposed facility is being designed with careful consideration of measures to minimize noise impacts in the surrounding community (Exh. BP-DK-3, at 41). Specifically, to mitigate continuous-source noise, the proposed facility would incorporate: (1) additional muffling above standard amounts in the gas turbine exhaust stream, and full enclosure of the gas turbine exhaust duct and muffler upstream of the HRSG; (2) location of the cooling tower on the east side of the facility, with noise barrier walls or equivalent noise control treatment on the south and north ends and west side of the cooling tower fan deck, and at ground level on the south end of the tower; and (3) acoustic lagging of outdoor piping and valves at the gas metering station (id.; Exh. BP-1B at 7-118).

In response to Siting Board staff requests, BPD identified options to further mitigate noise impacts from operation of the proposed facility (Exhs. HO-E-67; HO-E-68; Tr. 7, at 36-40). BPD identified three mitigation measures that could be successively added to reduce the proposed eight-dBA nighttime L_{90} increase at the nearest residential receptor, located at Moylan Lane to the southwest of the facility: (1) enclosure of the cooling tower with eight feet or more of parallel baffles, reducing the Moylan Lane receptor L_{90} increase by one dBA, to seven dBA; (2) installation of high-attenuation louvers on the turbine building ventilation intake, further reducing Moylan Lane receptor L_{90} increase by one dBA, to six dBA; and (3) doubling the size of, and enclosing, the exhaust duct muffler, further reducing Moylan

Lane receptor L_{90} increase by one dBA, to five dBA (Exh. HO-E-64).[193] To further reduce noise impacts to the east of the facility, BPD also identified the option of extending the cooling tower fan deck barrier, currently proposed for three sides of the tower, to the remaining east side, and installing a ground level barrier on the east side (Exh. HO-E-63). BPD indicated that the additional cooling tower barriers would reduce the proposed nighttime L_{90} increase by 11 dBA at the northeast property line receptor, from 34 dBA to 23 dBA, and by ten dBA at the southeast property line receptor, from 28 dBA to 18 dBA (Exh. HO-E-63; Tr. 7, at 21-22).

ii. Alternative Site

The Company stated that the proposed facility, if sited at the alternative site, would include the same noise mitigation features as at the primary site (Exh. BP-1B at 8-53). BPD further stated that it conducted an analysis of estimated facility noise and background noise during daytime and nighttime hours for three noise-sensitive receptor locations -- two residences and a school (id. at 8-53 to 8-55). The Company asserted that noise impacts of the proposed facility at the alternative site would be consistent with the MDEP ten-dBA limit and the EPA 55-dBA guideline, and would be minimized consistent with the Siting Board's standard (Company Brief at 117).

In support of its position, BPD cited results of its analysis indicating that operation of the proposed facility would cause nighttime L_{90} increases of nine dBA at both residential receptors, but result in no nighttime increase at the high school and no daytime increase at any receptor (Exh. BP-1B at 8-58). The Company estimated that average construction noise levels at the nearest residences would be 60 dBA during the erection phase and the finishing phase, with lesser levels ranging from 49 to 56 dBA during the remainder of the construction period (id. at 8-57).

193 The Company indicated that, to be effective, the three options must be applied successively, in the order identified, because it is necessary to address a source with a louder impact at the identified receptor before addressing a source with a less loud impact (Tr. 7, at 43-44).

With respect to operating noise impacts, BPD acknowledged that it assumed a plant layout corresponding to that at the primary site, and did not optimize the layout to minimize noise impacts for the alternative site surroundings (Tr. 7, at 65). In addition, in response to a request of the Siting Board staff, BPD considered a site-specific option to further mitigate noise impacts at the nearest residence located south of the site at Great Brook Drive, and confirmed that, conceptually, a noise barrier could be placed along a bluff near the receptor to reduce the nighttime L_{90} increase to between five and eight dBA (Exh. HO-RR-36).[194]

The Company noted that the maximum nighttime noise increase at the nearest residences would be slightly greater at the alternative site than the primary site, and therefore concluded that the primary site would be slightly preferable to the alternative site with respect to noise impacts (Company Brief at 118; Exh. BP-1B at 8-59).

iii. Analysis

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable governmental regulations, including the MDEP's ten-dBA guideline. Cabot Decision, 2 DOMSB at 406-407; Altresco Lynn Decision, 2 DOMSB at 197; 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 dBA, may adversely affect existing residences or other sensitive receptors such as schools. 1993 BECo Decision, 1 DOMSB at 104-106; Enron Decision, 23 DOMSC at 310-311; NEA Decision, 16 DOMSC at 402-403.

Here, BPD's noise analysis indicates that, for three residential receptors located north, south and southwest of the primary site, facility operation would result in nighttime L_{90} increases of seven to eight dBA above current L_{90} levels, ranging from 31 to 33 dBA.

194 Mr. Keast stated that a number of residences in the vicinity of the receptor may warrant shielding under the identified option, requiring a barrier 1,300 feet in length (Exh. HO-RR-36; Tr. 7, at 61-64). He indicted that the barrier would need to be sufficiently high to shield second story windows from the noise from the cooling tower (id.).

During the day, facility operation would result in L_{90} increases of two dBA or less at all five residential receptors. For primary site property line receptors, all of which abut non-residential land, nighttime L_{90} increases would be well above the ten-dBA limit at all such receptors, while daytime L_{90} would be significantly above the ten-dBA limit for the two receptors located at the northeast and southeast corners of the site.

The Siting Board notes that the proposed eight-dBA increase in nighttime L_{90} noise at the nearest residential receptor would be the largest such noise increase ever accepted by the Siting Board.[195] BPD maintains that the nighttime noise impacts of the proposed facility would be adequately minimized, however, because the maximum contribution of the facility to L_{dn} noise at any residential receptor is well below the EPA 55-dBA guideline, and because the maximum nighttime L_{90} noise at any residential receptor, with operation of the proposed facility, is well below corresponding worst-case impacts in other Siting Board reviews of generating facilities.

The Company's argument regarding lower nighttime L_{90} estimates in this review than in earlier Siting Board reviews appears to have merit, not only for the nearest residential receptor but for all five residential receptors in BPD's analysis. With respect to L_{dn} noise, however, the Company focuses on noise from the proposed facility rather than combined background and facility noise.

In a past review, the Siting Board cited concerns with an estimated combined L_{dn} of 59 dBA at affected residential receptors -- a level clearly over the EPA 55-dBA guideline -- and based on that concern limited L_{90} increases to no greater than five dBA. <u>1993 BECo Decision</u>, 1 DOMSB at 108, 109, 114. Here, BPD's 24-hour measurements indicate residential L_{dn} levels likely would not exceed 55 dBA with operation of the proposed facility, but nonetheless likely would approach that limit. We agree, therefore, that the likely impacts of the proposed facility as reflected in residential L_{dn} levels are acceptable, and note that the

195 In an earlier case, the Siting Board accepted an increase in nighttime L_{90} of seven dBA, from 41 to 48 dBA, but cited its concern that such an increase could result in abutter complaints. <u>NEA Decision</u>, 16 DOMSC at 401-403.

estimated residential L_{dn} contributions of less than 55 dBA from the facility itself may well have been significant in holding combined facility and background L_{dn} to acceptable levels. We also note, however, that in different circumstances where background L_{dn} already might exceed 55 dBA, it would be important to avoid further increases in either L_{dn} or nighttime L_{90} that might be large enough to result in abutter complaints.

With respect to noise impacts in areas near the northeast and southeast property line receptors at the primary site, the record indicates that daytime L_{90} increases of ten to as much as 24 dBA would extend 450-750 feet into abutting vacant land owned by WMECo and adjacent industrial parcels at the end of Industrial Lane. BPD has demonstrated that the affected areas are not zoned to allow residential use, and also asserts that estimated noise in such areas would meet non-residential guidelines to prevent hearing loss and other concerns.

The Siting Board has not previously reviewed noise increases, nor resultant combined facility and background noise levels, of the magnitude proposed by BPD. Further, although BPD cites instances in which MDEP has accepted noise increases at non-residential property lines that are significantly over ten dBA, it is unclear that MDEP would accept noise increases of the magnitude proposed by BPD, particularly given the inclusion of currently vacant land as part of the affected area. The Siting Board notes that, in addition to the options to extend noise barriers to the east side of the cooling tower, acquisition of land or easements in the affected off-site area also might mitigate the above-mentioned impacts.

The record includes BPD's consideration of options that would further minimize noise impacts from operation of the proposed facility. Such options would reduce expected noise increases that: (1) would be well above the three-dBA threshold for noticeable noise; (2) would approach the MDEP ten-dBA limit at residential receptors and significantly exceed that limit at property line receptors; and (3) would be larger than increases previously accepted by the Siting Board. However, BPD has not proposed to implement options to further minimize noise impacts from operation of the proposed facility, citing cost and limited effectiveness.

Accordingly, the Siting Board finds that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise. The Siting Board addresses the appropriate balance between identified options for further mitigation and other cost and environmental factors in Section III.B.4, below.

The record indicates that the residential and other sensitive receptor noise impacts of the proposed facility at the alternative site would be nearly identical to those at the primary site, and that identified options for further noise mitigation at the primary site likely could be applied at the alternative site. Further, the proposed facility at the alternative site would closely abut off-site vacant land on one or two sides, as it would at the primary site on three sides. Despite these similarities, the Company argues that the primary site is slightly preferable, citing residential L_{90} results. At the same time, BPD acknowledges the potential to optimize the plant layout and possibly install a residential noise barrier at the alternative site. Additionally, the Siting Board notes that the overall ability to minimize property line noise impacts may be more favorable at the alternative site because (1) the alternative site is larger than the primary site, and (2) off-site land that would closely abut the facility at the alternative site consists of previously worked gravel quarry area, which may provide a better opportunity than at the primary site for BPD to acquire additional buffer to avoid or mitigate high property line noise impacts. Finally, we note that construction noise levels at the nearest residence would be slightly less at the alternative site.

Accordingly, the Siting Board finds that the primary site would be comparable to the alternative site with respect to noise.

e. Traffic

i. Primary Site

BPD asserted that the construction and operation of the proposed facility at the primary site would have minimal impacts on local traffic conditions and would result in a very small increase in trips in the traffic study area (Exh. BP-1B at 7-121).

In support of its assertions, BPD presented projections of trip generation and related traffic impacts with and without the proposed facility, including separate estimates of construction-related traffic and facility operation traffic (id. at 7-131, 7-135, 7-142). The

Company indicated that the majority of construction activity would occur between 7:30 a.m. and 4:00 p.m., Monday through Friday (id. at 7-129).[196] The Company indicated that the maximum number of employees at the site is expected to be 210, which would occur during construction in June 1998 (id.). To help quantify traffic generation, BPD presented a comparison of expected peak-hour levels of service ("LOS")[197] with and without the proposed project for each of the three primary gateway intersections, Silver Street and Shoemaker Lane, Shoemaker Lane and Suffield Street, and Silver Street and Suffield Street (id. at 7-121, 7-129, 7-135).[198] BPD stated that in estimating the number of trips created by the proposed project, it assumed 1.1 workers per car and that 50 percent of the workers would arrive and depart during the morning and evening peak periods (id. at 7-130).[199]

196 The Company stated that there might be limited circumstances when after-hours or weekend construction would be necessary (Exh. HO-E-66). However, BPD indicated that only a small number of workers would be on the site during such periods, and that the off-hours traffic therefore would have no appreciable impact (id.)

197 The Company indicated that the efficiency of traffic operations at a location is measured in terms of LOS (Exh. BP-1B at 7-123). LOS is measured in terms 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. at 7-123 to 7-124). LOS A through C are considered acceptable operating conditions in an area with characteristics similar to the proposed project study area, under guidelines established by MEPA and the Executive Office of Transportation and Construction (id.).

198 LOS was measured for eight critical intersection movements, including: Shoemaker Lane at Suffield Street -- all moves from South Street, left turn from Suffield northbound, left turn from Suffield southbound, right turn from Shoemaker, and left turn/through movement from Shoemaker; Silver Street at Shoemaker Lane -- left turn from Silver southbound, and all moves from Shoemaker; and Silver Street at Suffield Street (Exh. BP-1B at 7-126).

199 BPD asserted that its assumption that 50 percent of the construction-related traffic would coincide with the morning and evening peak overstates traffic impacts because the morning peak is from 7:30 a.m. to 8:30 a.m., while the construction work-day would begin at 7:30 a.m. (Exh. HO-E-68).

The Company indicated that the existing peak commuting periods in the area generally are 7:30 a.m. to 8:30 a.m. and 4:45 p.m. to 5:45 p.m. (id. at 7-123, 7-126).[200]

The Company asserted that the LOS analysis shows no adverse project impact on existing traffic conditions during construction (id. at 7-121). BPD stated that the only projected change in LOS due to construction-related traffic would occur at South Street during the morning peak, where service would degrade from a LOS B to a LOS C, which would still be an acceptable level (id. at 7-133).

The Company indicated that three intersection movements at the Shoemaker Lane and Suffield Street intersection currently operate at unacceptable traffic conditions -- LOS E during the evening peak for all movement from South Street, and LOS D and LOS F during the morning and evening peaks, respectively, for the left turn/through movement from Shoemaker (id. at 7-129). The Company asserted that construction-related traffic would not significantly exacerbate the existing unacceptable conditions at this intersection, since LOS for all movements would remain the same under 1998 conditions with and without the proposed project (id. at 7-133, 7-141).[201] BPD stated that the increase in delay associated with the temporary decrease in reserve capacity would not be noticeable to the average commuter (Exh. HO-E-101). BPD indicated that it would develop construction and operation shift schedules to minimize any overlap of facility-related and general traffic patterns at the Shoemaker Lane and Suffield Street intersection (Exh. BP-1B at 7-141).

In addition to employee work trips, the Company indicated that there would be 30 delivery vehicle round trips per day during peak construction (id. at 7-130). The Company

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200 The recorded morning and evening peaks based on actual traffic counts for the three intersections analyzed are: (1) 7:15 a.m. - 8:15 a.m. and 4:00 p.m. - 5:00 p.m. at Shoemaker Lane and Suffield Street; (2) 8:00 a.m. - 9:00 a.m. and 4:15 p.m. - 5:15 p.m. at Silver Street and Shoemaker Lane; and (3) 7:30 a.m. - 8:30 a.m. and 4:15 p.m. - 5:15 p.m. at Suffield and Silver Streets (Exh. BP-FS-2 at App. I).

201 The reserve capacity, which is measured in vehicles per hour, would decrease at the left turn/through movement from the Shoemaker location (Exh. BP-1B at 7-135). The morning peak reserve capacity would decrease from 146 to 118, and the evening peak reserve capacity would decrease from negative 72 to negative 184 (id. at 7-135).

indicated that the regular delivery schedule would be 8:00 a.m. to 6:00 p.m., Monday through Friday, but that it would work to limit deliveries to before 4:30 p.m. (Exh. HO-E-66). The Company further indicated that delivery of very large equipment or pieces would be scheduled for weekend days and that the Company would coordinate such deliveries with the appropriate local officials (id.; Exh. BP-1B at 7-131).

The Company further stated that once the facility is fully operational, 25 employees would work at the proposed facility, spread over three shifts (id. at 7-138).[202] The Company asserted that its analysis shows no significant impacts to intersection capacity conditions when the facility is operational (id. at 7-141). BPD stated that there would be no change in LOS due to facility-related traffic (id. at 7-140).

In the event that oil-burning is necessary, BPD calculated that it would use oil at a rate of approximately 1.4 truck loads per hour, assuming replenishment of oil coincident with its use (Tr. 9, at 46) (see Section II.B.3.d, above). However, the Company stated that it would first draw down its three-day on-site supply of oil, and that in most cases it would not need to operate more than three days continuously on oil, thereby allowing it to replenish the on-site tank on a slower schedule (id.). In addition, BPD asserted that it has committed to both the Town Council and the Agawam Planning Board that it would use a specific preferred route and a backup route for the delivery of fuel oil and chemicals, and that it would limit the delivery of fuel oil and chemicals to between the hours of 9:30 a.m. to 2:00 p.m. to avoid conflicts with the Agawam school bus schedule (Exh. HO-E-67; Tr. 1, at 23).

ii. Alternative Site

BPD asserted that the construction and operation of the proposed facility at the alternative site would have minimal impacts on local traffic conditions, and would result in a

202 The Company stated that, although the workers would be divided into three shifts, it assumed for the purpose of the traffic study that all 25 employees would arrive during the morning peak and exit during the evening peak (Exh. BP-1B at 7-138).

very small increase in trips in the traffic study area (Exh. BP-1B at 8-60, 8-72). BPD also asserted that the traffic impacts of the proposed facility at the alternative site would be comparable to the traffic impacts at the proposed site in Agawam (id.).

In support of its assertions, BPD developed projections of trip generation and related traffic impacts, with and without the proposed facility at the alternative site, including separate estimates of construction-related traffic and facility operation traffic, based on the same assumptions used for the primary site (id. at 8-63, 8-68, 8-73). BPD indicated that all construction traffic would access the site from Hudson Drive, a limited destination access road that runs north from Route 57 (Exhs. HO-E-70; HO-E-71). BPD presented a comparison of expected peak-hour LOS for two primary gateway intersections, Route 10/Route 202 at Route 57 (Feeding Hills Road),[203] and Route 57 at North Longyard Road (Exh. BP-1B at 8-60, 8-68, 8-73). The Company asserted that the analysis shows no adverse project impact on existing traffic conditions during either construction or operation (id. at 8-60). The Company also conducted traffic counts at the Hudson Drive access, but stated that it did not conduct an LOS analysis since Hudson Drive is a limited access road with limited associated turning movements (Exh. HO-E-71).

The Company indicated that it did not conduct an analysis of Southwick school bus schedules or develop specific strategies to minimize potential traffic conflicts (Exh. HO-E-67). BPD stated that in the event that the proposed facility was to be constructed at the Southwick site, the Company would work with Town and school officials to minimize traffic impacts (id.).

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203 Feeding Hills Road is a bi-directional roadway that runs east to west from Route 10/202 to Agawam (Exh. BP-1B at 8-61). During the morning peak hour under 1998 construction conditions, 534 cars would be traveling east, with 39 turning onto Hudson Street, and 379 cars would be traveling west, with 59 cars turning onto Hudson Street (id. at Figures 7.9.4, 7.9.5). In comparison, for the primary site, at the morning peak 201 cars would be traveling east along Shoemaker Lane, with 10 cars turning onto Moylan Lane, and 219 cars would be traveling west, with 88 cars turning onto Moylan Lane (id. at Figures 8.9.4, 8.9.5).

iii. Analysis

The record indicates that increased vehicular traffic due to construction and operation of the proposed facility at the primary site would not cause adverse impacts for most key intersection movements in the vicinity of the facility. However, the Siting Board notes that various points of critical movement at the intersection of Suffield Street and Shoemaker Lane currently operate at an unacceptable LOS level during both morning and evening peak periods, most significantly at a LOS of F for the evening peak for the left turn/through movement from South Street.[204] Further, the morning peak hour at this critical intersection begins at 7:15 a.m., a time when a significant number of workers could be expected to arrive for the 7:30 a.m. shift. Thus, the Company's assumption that 50 percent of the workers would arrive between 7:30 and 8:30 a.m. may understate the impact of construction on this intersection.

The Company's assumption also understates the effect of construction traffic during the evening peak period, which falls between 4:00 and 5:15 p.m. at analyzed intersections. Since the construction shift ends at 4:00 p.m., it is likely that nearly 100 percent of employees would depart during the evening peak. Further, the evening peak is when the Suffield Street and Shoemaker Lane intersection experiences its worst LOS.

BPD has stated that it would develop construction and operation shift schedules to minimize arrivals and departures during peak commuter hours at the Suffield Street and Shoemaker Lane intersection. However, the Siting Board notes that, given the anticipated shift schedules, construction traffic will overlap with peak commuter hours in both the morning and evening periods at this already congested intersection. Therefore, the Siting Board requires BPD, in consultation with the Town of Agawam, to develop and implement a

204 Although BPD maintains that unacceptable levels of LOS D, E, and F would be at the same level with either baseline 1998 conditions or with 1998 construction conditions, the proposed project would worsen the already negative reserve capacity at the evening peak by 155 percent at Suffield Street and Shoemaker Lane. While LOS is a method of classifying traffic conditions, the Siting Board notes that significant increases in traffic can result in increased delays and worsening traffic conditions, even while remaining within the same unacceptable classification.

traffic mitigation plan which includes scheduling to avoid peak travel periods, route modification, or other appropriate measures to minimize construction-related traffic impacts at the Suffield Street/Shoemaker Street intersection during actual intersection peak periods.

Accordingly, the Siting Board finds that, with the implementation of the aforementioned condition, the environmental impacts of the proposed facility at the primary site would be minimized with respect to traffic impacts.

The Siting Board notes that, in general, increased vehicular traffic due to construction and operation of the proposed facility at the alternative site would not cause significant impacts at key intersections in the vicinity of the facility, and that LOS ratings would remain acceptable for the study area. However, given the heavy traffic on Route 57, the construction-related traffic entering and exiting the site via Hudson Drive has the potential to cause delays in traffic along Route 57. If the proposed facility were to be constructed at the alternative site, the Company should develop a traffic mitigation plan in consultation with Southwick officials. Such a plan might include posting traffic control personnel at the intersection of Hudson Drive and Route 57 during the peak hours of construction and commuter traffic.

Accordingly, the Siting Board finds that the primary site would be comparable to the alternative site respect to traffic impacts.

f. Safety

With respect to safety issues associated with the construction and operation of the proposed facility, the Company asserted that all activities and equipment at the primary or the alternative site would conform to regulatory standards and GEP (Exh. BP-1B at 7-145, 8-76). The Company described a number of measures that would ensure safety during construction, consisting of: (1) requiring contractors to have regulatory compliance programs in place; (2) including provisions in construction contracts that require contractors to adhere to safety and health requirements; (3) including audit, penalty and termination provisions in construction contracts to guarantee full contractor performance relative to health and safety requirements; and (4) managing and containing chemicals in accordance with all relevant regulations, including containment and off-site safe disposal or re-use of chemical cleaning agents (id.).

The Company asserted that safety and emergency systems designed for the proposed facility would ensure its safe operation at either the Agawam or Southwick site (id.). The Company stated that, among other important safety features, the facility design would include: containment basins or dikes for all hazardous material storage areas; automatic shutdown systems with backup power supply for the turbines and fuel supply systems; and a number of fire prevention and control measures (id.). The Company indicated that continuous monitoring of operations at the proposed facility and a program of regular maintenance would provide additional guarantees that the proposed facility would operate safely (id.). The Company also stated that it would prepare a comprehensive "safety and health action plan," which would include the training of all employees in emergency procedures and the coordination of emergency response plans with local emergency support services (id.). The Company stated that, in addition to taking other security measures, it would install a fence to prevent unauthorized individuals from gaining access to the proposed facility during construction and operation (id.).

i. Materials Handling and Storage

The Company indicated that aqueous ammonia, and all other non-fuel chemicals to be stored on site at the proposed facility, would be managed in accordance with all applicable public and occupational safety and health standards (id. at 7-147, 8-76 to 8-77). The Company indicated that, in conjunction with the Agawam Town Council and the Agawam Planning Board, it had developed a delivery schedule and route for fuel oil and chemicals that would minimize potential conflicts with traffic in general and with school bus activity in particular (Exh. HO-E-67 at 1, (att.)). The Company stated that if the proposed facility were built at the alternative site, it would develop a comparably safe delivery schedule and route in cooperation with Southwick town and school officials (id. at 2).

The Company described the steps it had taken to control potential safety and health risks associated with aqueous ammonia, stating that the unloading area would be proximate to the aqueous ammonia storage tank, completely curbed, and designed to hold any spillage from a truck (Tr. 9, at 48-49). The Company indicated that sensors and alarms would be installed as an added precaution in the proposed handling area (Exh. BP-1B at 7-148, 8-76). The Company stated that aqueous ammonia would be stored in one 12,000 gallon tank[205] surrounded by a containment dike to prevent accidental damage from vehicles and large enough to hold the entire contents of the tank without discharge (id.). The Company stated that the containment dike would be covered with floating ball-like baffles to reduce the surface area of an accidental spill from the proposed project and thus the predicted concentrations of an ammonia leak (Exhs. HO-E-1(att).; HO-E-72). To reduce the potential surface area of a spill still further, the Company agreed during the proceedings to redesign the storage tank to permit construction of a narrower, higher-walled containment dike (Exh. HO-RR-54).

The Company stated that aqueous ammonia would be transported, handled, stored and used in the same manner at the Southwick site as at the Agawam site (Exh. BP-1B at 8-76 to 8-77; Company Brief at 126).

ii. Fogging and Icing

The Company stated that it used five years of meteorological data and the Seasonal/Annual Cooling Tower Plume Impact ("SACTI") model[206] to determine the likely frequency and location of fogging and/or icing due to evaporative cooling for the proposed facility at both the primary site in Agawam and the alternative site in Southwick (Exh. BP-1B at 7-44 to 7-45, 8-6 to 8-7). The Company stated that it modelled facility emissions over a five-year period and determined that occurrences of ground-level fogging at the rate of one

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205 The Company asserted that one storage tank rather than multiple smaller tanks reduced the likelihood of leaks and operational problems, as well as the frequency of deliveries and associated risks (Tr. 3, at 119-120).

206 The SACTI model is an outgrowth of work sponsored by the EPRI (Exh. BP-FS-2, at 3-36). The Company characterized the SACTI model as "conservative," i.e., as tending to overpredict the incidence of fogging and icing (Tr. 10, at 119-122).

hour per year or greater would be limited to an area within the proposed site boundary (Exh. BP-FS-2, at 3-36). The Company further determined that ground level icing at a location immediately west of the property boundary of the Agawam site would be limited to a single 0.4-hour episode over a five-year period, and noted that this location is not near any public roadway (id.). The Company also stated that natural fog, rain or snow was likely to occur coincident with fogging or icing from the cooling tower (id.).

The Company asserted that impacts from fogging and icing associated with operation of the proposed project at the Southwick site would be comparable to those at the primary site (Exh. BP-1B at 8-7). In support of its assertion, the Company noted that fogging exceeding one hour per year in frequency at the alternative site would likely be limited to one area within 200 meters of the cooling tower, extending southward (id. at 8-6 to 8-7). The Company further indicated that icing would not exceed one hour per year in any direction at the alternative site (id. at 8-7). In addition, the Company stated that natural fog, rain or snow would likely occur coincident with fogging or icing from the cooling tower at the Southwick site (id.).

CCBA contended that dangerous fogging and icing might occur at the proposed facility at the primary site (CCBA Brief at 4-5). CCBA based its assertion in part on (1) analyses and reports of fogging and icing associated with a cooling tower in Iowa, and (2) statements, attributed to victims of traffic accidents in the vicinity of an existing Massachusetts generating facility and cooling tower, which alleged cooling-tower-induced icing at the time of the accidents (id.; Exh. CCBA-2). CCBA also maintained that the evaporative water tower might incubate legionella bacteria and result in illness to abutters in the vicinity of the proposed facility (CCBA Brief at 5). CCBA supported its assertion with a range of newspaper articles and studies written over a twenty-year period that address the occurrence of legionella in a variety of locations and structures distinct from the proposed cooling tower (id.; Exhs. CCBA-4; CCBA-5; CCBA-6; CCBA-7; CCBA-8; CCBA-9; CCBA-10; CCBA-11).

In response to CCBA's assertions, the Company argued, that CCBA: (1) relied primarily on non-record information regarding alleged fogging and icing incidents occurring near other industrial facilities; (2) ignored differences between those facilities and the proposed facility with respect to distances between the affected roads and cooling towers; (3) provided no evidence of nexus between the alleged incidents on roads near the existing facilities and the likelihood that similar incidents would occur near the proposed facility; and (4) did not address the Company's SACTI analysis of the proposed facility's likely fogging and icing impacts (Company's Reply Brief at 4-5).

iii. Analysis

The record demonstrates that aqueous ammonia, and all other non-fuel chemicals to be stored on site at the proposed facility, will be managed in accordance with all applicable public and occupational safety and health standards. With respect to chemical storage and handling, the record demonstrates that the Company has designed facilities for the proposed project to avert spills of hazardous materials at either site and to contain any such accidental spills. The Siting Board particularly notes the Company's readiness to modify the design of the proposed aqueous ammonia storage tank and containment dike to minimize evaporation of ammonia in case of a spill. Further, the Siting Board notes that BPD intends to develop emergency procedures and response plans similar to those found acceptable in previous Siting Board decisions. See Cabot Decision, 2 DOMSB at 417; Altresco Lynn Decision, 2 DOMSB at 211; 1993 BECo Decision, 1 DOMSB at 145.

The record demonstrates that fogging and icing associated with the evaporative cooling tower for the proposed facility at both the Agawam and Southwick sites would be limited to on- or near-site locations, and would not occur on public roadways. The Siting Board notes that the record contains no site-specific analysis that would dispute the validity of the Company's analysis of fogging and icing impacts associated with the proposed project at either the primary or the alternative site. However, in order to alleviate public concern in this area, the Siting Board directs the Company to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, establish a plan in cooperation with local officials to alert motorists and residents concerning any project-related fogging or icing episodes affecting public safety.

Accordingly, the Siting Board finds that, with the implementation of the above condition, the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety. In addition, the Siting Board finds that the primary site would be comparable to the alternative site with respect to safety.

g. Electric and Magnetic Fields[207]

i. Primary Site

The Company indicated that operation of the proposed facility would produce magnetic field increases associated with (1) the new on-site tie line, which would transmit the project's 252 MW output to the nearby WMECo 115 kV transmission line, and (2) increased power flows on certain existing transmission lines during various load conditions (Exh. BP-1B(att. 7.12.1); Exh. HO-E-76).[208] BPD asserted that the expected increases in magnetic field from the tie line would be minimal or non-existent off the site, with a maximum property line increase of two milligauss ("mG") and no increase at any residence (Company Brief at 128). BPD further asserted that magnetic field increases at the edge of the ROW along existing transmission lines would be insignificant, noting that total magnetic field levels at such locations would remain well below an acceptable maximum of 85 mG recognized by the Siting Board (id.). Finally, BPD indicated that it is pursuing arrangements with WMECo to incorporate double circuit phase configurations that would minimize magnetic field levels along certain existing transmission system ROWs near the site, including (1) the transmission system segment extending to the nearest substation north of the

207 Electric and magnetic fields produced by the presence of voltage and the flow of current are collectively known as electromagnetic fields ("EMF").

208 The Siting Board notes that WMECo's and other utilities' 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 at both sites, the Siting Board may identify and evaluate any potentially significant effects of the facility on EMF levels along existing transmission lines. See Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

site, in which BPD expects partial reconductoring would be required, and (2) an additional segment further to the north (id.).[209]

In support of its assertions, BPD provided calculations of magnetic field levels near the site with and without operation of the proposed facility tie line, indicating that the tie line would produce (1) an increase from zero to two mG at the east property line, abutting WMECo, and (2) no increases elsewhere along the site boundary above existing levels, which range from zero to a maximum of 41 mG nearest the existing WMECo transmission line traversing the site (Exh. BP-1B(att. 7.12.1) at Table 1). In addition, based on power flow projections in an interconnection study by BPD's consultant, R.W. Beck, BPD provided calculations of magnetic field levels at the edge of three affected transmission line ROWs in the year 2000, with and without the proposed project and under peak and off-peak conditions (id., Table 2; Exh. HO-V-19(att.)). BPD's calculations show that the greatest increases in magnetic field would be (1) for peak load periods, an increase from 13.4 mG to 26.8 mG on the transmission system segment between the site and the North Bloomfield substation, to the southwest in Connecticut, and (2) for off-peak periods, an increase from 13.4 mG to 36.9 mG on the segment between the site and the South Agawam junction, north of the site (Exh. BP-1B(att. 7.12.1) at Table 2).[210]

Regarding the calculated peak load increase in magnetic field levels between the site and the North Bloomfield substation, BPD asserted that such conditions would occur infrequently, for a few minutes to an hour each year (Exh. HO-E-76). BPD's witness,

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209 The Company indicated that its analysis shows the proposed tie line also would result in little or no increase in off-site electric field levels (Exh. BP-1B(att. 7.12.1)). BPD added that there would be no increase in electric field levels along existing transmission line ROWs with operation of the proposed project because operating voltages would remain the same (id.).

210 The Company indicated that both segments consist of two three-phase circuits in which similar phases have been connected together to form a single transmission line (Exh. HO-RR-2). The segment to the South Agawam junction is one-half mile in length, and the segment to the North Bloomfield substation is approximately ten miles in length (id.; Exh. HO-V-19(att.), Attachment C).

Mr. Roberts, indicated that the affected segment extends through a primarily rural area with occasional street crossings and a few homes near the ROW (Exh. HO-S-22; Tr. 13, at 84-85).

Regarding the calculated off-peak load increase in magnetic field levels between the site and the South Agawam junction, BPD indicated that, if the existing line is reconductored and operated in a double circuit configuration with reversed phases, as BPD recommends, the magnetic field level would be 10.7 mG rather than 36.9 mG, resulting in a reduction rather than an increase in magnetic field levels due to the proposed project (Exhs. BP-1B(att. 7.12.1); HO-E-76; HO-E-104). BPD indicated that reversing phases in the reconductored line would result in similarly reversed phases with a corresponding reduction in magnetic field levels for the existing double circuit line continuing north from the South Agawam junction to the Silver Street substation, one mile north of the site (Exhs. HO-S-6; HO-S-22; Tr. 1, at 32-34; Tr. 13, at 78-79). The ROW between the site and the Silver Street substation crosses Silver Street, where there are nearby residences, but otherwise traverses predominantly undeveloped land (Exhs. BP-1B, fig. 7.6.2; HO-S-22; Tr. 1, at 32-34).

The Company indicated that the double circuit transmission line segment north of Silver Street substation, extending approximately three miles to the Agawam substation near the Westfield River, also would show significant increases in off-peak power flow with operation of the proposed project (Exh. HO-V-19(att.), cases A-19, A-20; Tr. 13, at 79, 83). BPD stated that reverse phasing likely could be accomplished without reconductoring in the segment between Silver Street and the Agawam substations, and added that it has requested that WMECo consider modifications to implement such reverse phasing (Exh. HO-RR-80; Tr. 13, at 80; Company Brief at 129). Mr. Roberts testified that he had walked that ROW segment, and that it traverses some built-up areas that include 20 to 30 homes abutting the ROW (Tr. 13, at 81-82).

ii. Alternative Site

The Company stated that the proposed facility, if sited at the alternative site, would produce magnetic field increases associated with (1) the 4.5-mile tie line, which would transmit the project's 252 MW output to the WMECo 115 kV transmission line southwest of the site, and (2) increased power flows on certain existing transmission lines during various load conditions (Exh. HO-E-76). BPD asserted that magnetic field increases at the site boundary and at the edge of the ROW along the tie line and existing transmission lines would be insignificant, noting that total magnetic field levels at such locations would remain well below an acceptable maximum of 85 mG recognized by the Siting Board (id.).[211] BPD asserted that the primary site is slightly preferable to the alternative site with respect to EMF impacts (Company Brief at 130).

In support of its assertions, the Company indicated that the tie line would produce maximum magnetic field levels at the edge of the ROW of 3.7 mG along the 3.5-mile underground portion and 57.2 mG along the one-mile overhead portion (id., Table 1). BPD also provided calculations showing that the greatest increases in magnetic field at the edge of existing transmission line ROWs would be (1) for peak load periods, an increase from 2.5 mG to 13.7 mG between the tie line and the North Bloomfield substation, to the south in Connecticut, and (2) for off-peak periods, an increase from 9.9 mG to 29.0 mG between the tie line and Grandville junction, to the north (id.).

iii. Analysis

In a previous review of proposed transmission line facilities which included 345 kV transmission lines, the Siting Board accepted edge-of-ROW levels of 1.8 kV/meter for the

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211 The Company asserted that the tie line also would not result in a significant increase in electric field levels at the site boundary or the edge of the tie line ROW, citing an expected increase of 0.38 kV/meter at the edge of the ROW (Exh. HO-E-76). BPD added that there would be no increase in electric field levels along existing transmission line ROWs with operation of the proposed project because operating voltages would remain the same (id.).

electric field and 85 mG for the magnetic field. 1985 MECo/NEPCo Decision, 13 DOMSC at 228-242. Here, off-site electric field and magnetic field levels would show little or no change with operation of the tie line, and would remain well below the levels found acceptable in the 1985 MECo/NEPCo Decision. In addition, a portion of the regional 115 kV transmission line owned and maintained by WMECo, and into which the proposed facility would interconnect, likely would be reconductored by WMECo as part of such interconnection using a phase configuration that would minimize any magnetic fields between the site and Silver Street substation as a result of operation of the proposed project. Finally, as part of its interconnection agreement discussions with WMECo, BPD has and will continue to pursue modifications by WMECo to the phase configurations of existing transmission lines between WMECo's Silver Street and Agawam substations, so as to minimize any magnetic fields along such transmission lines as a result of operation of the proposed project.

The record demonstrates that the Company's interconnection plans include reasonable efforts to implement measures to minimize EMF impacts on portions of the existing transmission system affected by the proposed facility. Based on the Company's representations, the Siting Board expects that, as part of any BPD interconnection agreement with WMECo that provides for modifications to existing WMECo lines serving the site, BPD would seek inclusion of the transmission designs discussed herein to minimize magnetic field impacts through the phase configuration of such lines serving the site.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the primary site would be minimized with respect to EMF.

Operation of the proposed facility at the alternative site would result in greater overall EMF impacts than at the primary site, based on the incremental exposure along the 4.5-mile tie line, particularly the one-mile overhead portion thereof. Accordingly, the Siting Board finds that the primary site would be preferable to the alternative site with respect to EMF impacts.

h. Land Use

i. Primary Site

The Company asserted that the proposed facility at the primary site is fully compatible with land use and development in the surrounding area (Exh. BP-1B at 7-90). BPD further asserted that the proposed facility would be compatible with current land use characteristics and zoning for the site and surrounding areas, and would be consistent with relevant Agawam and regional development objectives (id. at 7-82).

BPD stated that the project site is an approximately 40-acre undeveloped site located in an area designated as the Shoemaker Industrial Park ("Industrial Park") (id. at 7-83; Exh. HO-E-51).[212] The Company indicated that the portion of the site to be developed, ten acres in area, is primarily an open grassy field currently used as a private small aircraft runway and for cultivation (see Exhibit C, map of site) (Exh. BP-1B, at 7-68, 7-83, fig. 7.6.3). The remainder of the site consists of woods and wetland, extending approximately 1,500 feet south to frontage on Shoemaker Lane (id.). BPD asserted that the size of the site is sufficient to accommodate the proposed facility and its ancillary components and to provide a significant buffer for surrounding land uses (id. at 7-90).

The Company asserted that the area within a one-mile radius of the proposed facility site can be characterized as mixed-use, consisting primarily of commercial and industrial development in the Agawam Industrial Park -- a second industrial park in that area -- and along Shoemaker Lane and Silver and Suffield Streets (id. at 7-88). The Company categorized the abutting land uses as industrial operations, vacant industrially zoned land, and commercial properties (id. at 7-86). Specifically, BPD reported that the property is bounded to the north and east by undeveloped, open and heavily wooded land owned by WMECo, to

212 The Industrial Park is bounded by Shoemaker Lane, Silver Street, and Suffield Street (Tr. 4, at 24). The Industrial Park is not fully occupied; however BPD reported that Agawam is currently recruiting new businesses to the Industrial Park (Exh. HO-E-51). The largest single landowner in the Industrial Park is WMECo (Tr. 13, at 118). The Park is not subject to any guidelines or covenants except for the applicable Agawam Zoning By-laws (id. at 114-115).

the southeast by a construction company and other commercial and industrial properties, to the southwest by a bus company, to the west by a residence, church, and undeveloped parcels, and to the northwest by SCBI (id. at 7-86 and 7-87).[213] The land use map provided by the Company indicates that within a half-mile radius of the proposed facility site, the land use is approximately 50 percent open or vacant, 25 percent industrial/commercial, and 25 percent residential or agricultural (id. at Figure 7.6.3). Within the next half-mile ring, land use is mixed with approximately equal parts industrial/commercial, residential, agricultural, recreational, and open/vacant property (id.).

BPD stated that significant areas of residential development are located principally to the east of the proposed site, across Suffield Street, and that residences are intermixed with commercial and industrial development along Shoemaker Lane, Suffield and Silver Streets (id.).[214] The Company indicated that approximately 85 residences are located within a half-mile of the nearest proposed facility structure, and approximately 280 residences are within one mile of a proposed facility structure (Exh. HO-E-47).[215] The Company stated that the nearest residence is located approximately 1,200 feet southwest of the closest proposed facility structure, on Shoemaker Lane across from the entrance to Moylan Lane (id.). Further, the Company stated that the nearest residence to the site property line is located across Shoemaker Lane, approximately 100 feet to the south of the site (id.).

BPD asserted that power generation is allowed by right at the proposed site under the applicable zoning district, Industrial B,[216] which allows any industrial purpose not expressly

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213 SCBI is presently the only development on Moylan Lane (Exh. BP-1B, at 7-87).

214 The land use map provided by the company indicates that the majority of the residential land use within a half-mile radius of the site is located on the south side of Shoemaker Lane (Exh. BP-1B at fig. 7.6.3).

215 These numbers were estimated based on the 1983 Agawam Board of Assessors Map, the 1979 USGS West Springfield Quadrangle map, an April 1990 aerial photograph, and field observations (Exh. HO-E-47).

216 The Town of Agawam has ten classes of zoning districts, including two industrial, five residential, one agricultural, and two business classifications (Exh. HO-E-48S).

excluded as hazardous or offensive to the surrounding community (Exh. BP-1B at 7-89). BPD explained, however, that the generation building, fuel oil storage tank, demineralized water storage tank, main stack and cooling tower exceed the 40-foot height allowed in an Industrial B district (id.). Therefore, the Company filed an application seeking a Special Permit[217] in accordance with Section 180-63 of the Agawam Zoning By-laws.[218] BPD's application for a Special Permit was denied on January 4, 1996 (Exh. HO-RR-62; Company Brief at 108).[219] BPD stated that it received site plan approval from the Agawam Planning Board on September 7, 1995 (Exh. BP-FS-6).

The area abutting the proposed site also is zoned Industrial B, with the exception of the south side of Shoemaker Lane near the southern boundary of the proposed site, which is zoned Residence A-3 (Exh. BP-1B at fig. 7.6.4). Within a one half-mile radius of the site, the area is zoned primarily Industrial B; however, there are residentially zoned areas south and southwest of Shoemaker Lane (id.).

The proposed site includes 10 acres of land that are classified by the Massachusetts Department of Food and Agriculture as agricultural land, the loss of which must be mitigated

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217 Mr. Roberts stated that BPD filled out the special permit forms at the direction of the Agawam zoning officer, in response to the Company's request for approval to exceed the 40-foot height limitation (Tr. 11, at 244).

218 Section 180-63, entitled "Height regulations," states: "Industrial buildings shall not exceed two (2) stories, forty (40) feet in height, except with approval of the Board of Appeals after a public hearing. These provisions shall not apply to required equipment appurtenant to industrial buildings, except that smokestacks, water tanks, grain elevators and the like are not permissible except after approval of the Board of Appeals after a public hearing" (Exh. HO-E-48(att.)).

219 The record indicates that the Agawam Zoning By-laws operate pursuant to authority granted under G.L. c. 40A, §§ 1-22 (Exh. HO-E-48). G.L. c. 40A, § 9 states that "a special permit issued by a special permit granting authority shall require .... a unanimous vote of a three member board." Two members of the Agawam Zoning Board of Appeals voted in favor of the application and one opposed it (Exh. HO-RR-62).

or compensated under G.L. c. 61A (Exh. HO-E-43).[220] BPD reported that it has committed to lease five acres of undeveloped land located on the northern portion of the site for the highest and best agricultural use (Exh. HO-E-1(att.) at 2-6; Tr. 13, at 27). In addition, any topsoils removed from this area during development would be used first for BPD's landscaping plan and then, if available, would be donated to local farms or greenhouses (Exh. HO-E-1(att.) at 2-8).

The Company stated that it would provide five acres of land on the eastern portion of the proposed site for community use (id.; Tr. 13, at 28). Further, the Company stated that it has committed to provide the Town with the right to access and use the southern portion of the site for recreational purposes (Exh. HO-E-46). The Company stated that the southern portion is wooded with the exception of an acre of cleared land in the southernmost portion of the site, and that it will be open to Town use with the provision that the Town not remove any trees that are serving as a visual buffer (Tr. 13, at 29).

BPD asserted that the proposed project would not adversely affect property values, and in fact should enhance property values due to the proposed in-lieu-of-taxes payments to the Town (Exh. CCBA-13; Tr. 11, at 182-183). Further, the Company asserted that analyses conducted in Massachusetts communities with power plants show no negative impact on property values, and in fact demonstrate that property values have increased beyond the general increase that would be expected in communities without power plants (Tr. 11, at 182-183).

The Company reported that electric transmission and sewer easements cross the northern portion of the proposed site (Exh. BP-1B at 7-69). BPD stated that the electric and sewer interconnections would occur on-site, and that gas and water interconnects would extend within roadways, thus minimizing land use impacts (id. at 7-90, 7-91).

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220 The ten-acre area is located in the northern portion of the proposed site (Exh. HO-E-1 (att.). at 2-6). Approximately three acres would be used for active development, and the remaining area would stay undeveloped and serve as a buffer (id.)

BPD asserted that the construction of the proposed facility would have no adverse impact on historical or archeological properties (id. at 7-86). An intensive archaeological survey of the project site by Public Archaeology Laboratory, Inc. determined that the property was not an historic period site (id. at 7-84, 7-86).

Country Estates argues that the primary site is not an appropriate location for the proposed facility due to the surrounding land uses, and argues that the land use impacts of the proposed facility are not acceptable (Country Estates Brief at 2, 3). Citing the Agawam ZBA decision denying the Special Permit, Country Estates asserts that: (1) the proposed facility would at times be a nuisance or potential hazard to vehicle or pedestrian safety; (2) the use of a smokestack in excess of 125 feet, a cooling tower in excess of 40 feet, and an oil storage tank are so objectionable as to be against the public interest and/or detrimental to the character of the neighborhood; and (3) the proposed facility is located in an area of residences, banquet and entertainment facilities, a nursing home, and commercial facilities, none of which have the type of equipment associated with the proposed facility (id. at 3).

CCBA argues that the proposed facility is in close proximity to abutters, and that the buffer zone between the proposed facility and abutters is not acceptable (CCBA Brief at 3). CCBA also argues that the proposed facility would have a detrimental effect on surrounding property values, citing language from an appraisal concerning marketability of a residence located near the NEA generating facility in Bellingham (id.).[221] The appraisal contained a location depreciation adjustment of seven percent due its the close proximity to the NEA generating facility (Exh. CCBA-16).[222]

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221 The appraisal states "the subject is located in close proximity to an electric power plant. The plant causes noise and an inferior view, therefore is considered an adverse influence to the neighborhood. It is the appraiser's opinion that the close proximity of this plant would affect the marketability of the homes in this neighborhood" (Exh. CCBA-16; CCBA Brief at 3).

222 CCBA also provided a letter from the owners of the NEA facility to the mortgage company that had contracted for the appraisal of the property (Exh. CCBA-16). NEA disputed the appraisal and pointed to steps it took to ensure that property values would (continued...)

CCBA argues that the development of the proposed facility is inconsistent with land use objectives outlined in two Agawam planning documents, "Industrial Planning Study"[223] and "Coming Together for Consensus: A Working Statement of Goals and Objectives to Guide Agawam into the Future" (Exh. L-RR-1; CCBA Brief at 4). CCBA stated that the proposed facility is not in compliance with the Agawam Zoning By-laws since it exceeds the 40-foot height limitation (CCBA Brief at 4).

Finally, CCBA argues that the primary site for the proposed facility is home to a rare and endangered species, the Eastern Box Turtle ("box turtle"), and that construction at the site will adversely impact the box turtle's habitat (Tr. 11, at 278; CCBA Brief at 7). In support of its contention, CCBA presented a witness, Amy J. Ringuette, who testified that she had observed box turtle specimens in the vicinity of the primary site on a number of occasions (Tr. 11, at 294). The witness indicated that her observations of the box turtle occurred at the edge of fields close to woodlands or in the woodlands themselves, and that the locations of the sightings were close to or bordering the primary site (id. at 299). The witness testified that fields and woodlands are the box turtle's prime habitat, but did not, under examination by the Company, disagree with the Natural Heritage and Endangered Species Program's ("NHESP")[224] conclusion that the box turtle's preferred habitat is open

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[222](...continued)
not be affected by the facility including: (1) construction of earthern berms and trees around the site; (2) gifts to individuals and neighborhood groups in excess of $100,000; (3) personalized school bus routes; and (4) direct contributions of over $1 million to the Town of Bellingham to maintain community services (id.). In addition, the Siting Board notes that NEA was ordered by the Siting Board to provide site specific mitigation through off-site tree planting. NEA Decision, 16 DOMSC at 71-72.

[223] The Industrial Planning Study reports that the Silver, Shoemaker, Suffield triangle is designed to provide locations for light industrial activities (Exh. L-1). The Industrial Planning Study was commissioned by the Agawam Economic Development Industrial Corporation and conducted by an independent consultant in April 1989 (id.).

[224] The NHESP is a program of the Massachusetts Division of Fisheries and Wildlife ("DFW").

deciduous forest (id. at 300, 304).[225] Ms. Ringuette testified that the range of the box turtle was two to eleven miles, but indicated that, as demonstrated by additional information provided by CCBA, the range of the box turtle was a matter of dispute (id. at 313).[226]

In response, the Company's witness, Frederick Sellars, testified that the Company had received letters from the U.S. Fish and Wildlife Service and NHESP indicating that neither agency was aware of any occurrences of rare plants or animals at the primary site (id. at 113; Exh. BP-FS-2, at (att. D)).[227] Mr. Sellars further testified that the box turtle has a limited home-range movement of from 150 to 750 feet; that a portion of the primary site was deciduous forest; and that the box turtle, if at the primary site, was likely to be located in the area of deciduous forest, its preferred habitat (Tr. 11, at 116-118). Mr. Sellars stated that construction for the proposed facility was not planned for the forested area, and that the parcel of deciduous forest would be maintained as a buffer area after construction of the proposed facility (id.). The Company therefore argued that constructing the proposed facility at the primary site as planned would, by preserving open deciduous forest, mitigate impacts to the habitat of the box turtle (id. at 117).

225 In fact, Ms. Ringuette indicated that she had contacted the NHESP in addition to the Agawam Conservation Commission and CCBA regarding her observations of the box turtle (Tr. 11, at 276, 322).

226 Material submitted by CCBA estimated the home range of the box turtle at 100 to 750 feet (Tr. 11, at 312).

227 In response to a request by the Siting Board, the Company inquired of NHESP as to whether a re-evaluation of that agency's findings would be necessary in light of Ms. Ringuette's filed observation with the NHESP, dated December 21, 1995 (Exh. HO-RR-75(supp.)). The Company provided a copy of a communication sent to the Massachusetts Environmental Protection Act office on February 27, 1996, from the DFW (id. at (att.)). In its communication, the DFW indicated that the design of the proposed BPD facility appeared to avoid impacts to the box turtles and their habitat (id.). The DFW also stated that it would require the Company to build a fence before beginning work on the proposed facility to prevent box turtles from entering the construction area (id.).

ii. Alternative Site

The Company asserted that the proposed facility at the alternative site is fully compatible with land use and development in the surrounding area (Exh. BP-1B at 7-90). BPD further asserted that the proposed facility would be compatible with current land use characteristics and zoning for the site and surrounding areas, and would be consistent with relevant Town of Southwick development objectives (id. at 8-42).

BPD stated that the alternative site is an approximately 200-acre site located within one of only two main industrially zoned districts in the Town of Southwick (id. at 8-23, 8-46). The Company also stated that the portion of the site to be developed currently operates as part of a sand and gravel business (id. at 8-43).

The Company categorized the land uses that abut the site as the remainder of the sand and gravel operation, undeveloped open space and wooded land, and residential properties (id.). Specifically, BPD reported that the property is bounded to the north, east, and southeast by undeveloped and heavily wooded areas, to the south by the sand and gravel removal area, to the south along Hudson Drive by limited light industrial development, to the southwest by undeveloped parcels, and to the west by scattered residential properties (id. at 8-43, 8-44). The land use map provided by the Company indicates that land use within a half-mile radius of the site is approximately 60 percent agricultural/open/vacant, 20 percent industrial/commercial, and 20 percent residential (id. at fig. 8.6.1). Within the next half-mile ring the land use is approximately 75 percent agricultural/open/vacant, 15 percent residential, and 10 percent industrial (id.).

BPD stated that the closest significant residential development is located to the south of the site beyond the sand and gravel operation (id. at 8-44). The Company indicated that there are approximately 100 residences located within a half-mile radius, and approximately 260 residences within a one-mile radius of the nearest proposed facility structure (Exh. HO-E-47).[228] The Company stated that the nearest residence is located on Great

228 The number of residences was approximated based on the Southwick Board of (continued...)

Brook Drive approximately 1,000 feet southwest of the nearest proposed facility structure (id.). Further, the Company stated that the nearest residence to the site property line is at the end of Sam West Road, approximately 150 feet from the site boundary (id.). The Company reported that there are three schools located along Route 57, the Woodland Elementary School, Powder Mill Middle School, and the Tolland Regional High School, all within approximately 4,000 to 4,500 feet of the proposed alternative facility site (Exh. HO-E-53).

The site is zoned Industrial Restricted, which requires that a Special Permit be granted by the Town of Southwick Planning Board before the proposed facility could be constructed (Exh. BP-1B at 8-45). The area surrounding the proposed site is zoned Industrial Restricted, with the exception of the eastern area, which is zoned Agricultural and Conservation (id.).[229] Within a one-half mile radius of the proposed facility at the alternative site, the area is zoned primarily Industrial Restricted and Agricultural and Conservation (id. at fig. 8.6.2).

BPD stated that off-site electric transmission and natural gas interconnects would be required, and that the electric interconnect would be 4.5 miles in length and the gas interconnect would be approximately one mile in length (id. at 8-24, 8-25). The electric interconnect route would begin as an overhead line from a WMECo substation, traveling overland to the east for approximately one mile to a former Penn Central Railroad ROW (id. at 8-24). From there, the interconnect would become an underground line for approximately 3.5 miles, traveling in a northerly direction to the proposed alternative site (id.). The Company asserted that since the proposed electric transmission interconnect would primarily follow a former railroad ROW, land use impacts would be minimal (id. at 8-36). The gas

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[228](...continued)
Assessors Map, the 1979 USGS Southwick Quadrangle map, and field observations (Exh. HO-E-47).

[229] A small portion of alternative site, located to the east, is zoned Agricultural and Conservation, but it is not within the development footprint (Exh. BP-1B at 8-45).

interconnect would begin one mile south of the proposed alternative site, traveling along Hudson Drive to Route 57, to a former railroad ROW, where it interconnects after a quarter of a mile with the Tennessee mainline (id. at 2-7, 2-8).

BPD asserted that the construction and operation of the proposed facility at the alternative site would be comparable to construction and operation at the proposed site with respect to land use impacts and community resources (id. at 8-47).

iii. Analysis

As part of its review of land use impacts, the Siting Board considers whether a proposed facility would be consistent with state and local requirements, policies, or plans relating to land use and terrestrial resources. Here, the record indicates that the primary site and surrounding areas are zoned for industrial use, that the abutting uses are a mixture of light industrial and commercial, and that the area within a mile radius of the primary site is divided equally between industrial, commercial, residential, and agricultural/vacant land.

The record also demonstrates that BPD's site selection process was designed to minimize the land use impacts of the chosen site (see Section III.A, above). The primary site was recommended for this purpose by the Town of Agawam, and the proposed facility is an allowed use under the Zoning By-laws of the Town of Agawam. Electric, gas, water and sewer interconnections at the primary site would require minimal off-site land, further limiting land use impacts. In addition, the Company has agreed to protections for agricultural land at the primary site.

Intervenors in this proceeding have raised a number of land use-related concerns regarding the primary site, including issues of safety, visual impacts, consistency with land use objectives and existing uses, adequacy of buffering, and property values. The Siting Board addresses visual and safety impacts issues in Sections III.B.2.c and III.B.2.f, above.

With regard to the consistency of the proposed facility at the primary site with land use objectives, the Siting Board notes that the proposed cooling tower and stack exceed the 40-foot height limitation in the Agawam Zoning By-law. While this has been true of most generating facilities previously reviewed by the Siting Board, many of these were to be located in the immediate vicinity of existing stacks or structures of a similar scale. See, e.g., Cabot Decision, 2 DOMSB at 420; Altresco Lynn Decision, 2 DOMSB at 199, n.232; MASSPOWER Decision, 20 DOMSC at 396. Here, the proposed structures are considerably taller and of a different scale than existing structures in the surrounding area. The Siting Board notes that BPD's petition to the ZBA for a Special Permit to exceed the 40-foot height limitation was denied, and that BPD must now seek appropriate relief before it can receive a building permit.[230]

However, the Siting Board also notes that the primary site was recommended to BPD for this purpose by the Town, and that the Company has received site plan approval from the Agawam Planning Board. Thus, while there may be differences of opinion within the community as to the desirability of locating a generating facility in the Industrial Park, the proposed facility is not clearly inconsistent with the Town's land use objectives for the primary site.

The Siting Board has considered the adequacy of buffering to limit visual and noise impacts of the proposed facility in Sections III.B.2.c and III.B.2.d, above.[231] Here, we note that, because the proposed facility structures are located near one end of the primary site, much of the on-site buffer extends to the south, with limited on-site buffer in the remaining three directions. However, the site abuts extensive vacant land owned by WMECo, which provides additional buffering in two directions.

With regard to property values, the Siting Board notes that the record does not provide a sufficient basis to conclude either that the proposed facility would have an adverse

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230 This is the first Siting Board review of a generation facility where a petitioner was refused the required zoning-related approval by the affected municipality to construct its facility to its basic specifications. The Siting Board notes that the issuance of a Special Permit by a local entity does not in and of itself determine Siting Board acceptance of the site land use impacts, and that the Siting Board conducts an independent review of the land use impacts.

231 The Siting Board further addresses noise impacts in Section III.B.4, below.

effect on property values, or that property values would remain stable or rise if the proposed facility were built at the primary site. Given anticipated facility noise impacts, the large scale of the proposed facility relative to existing development, and the expected on-site storage of backup fuel and chemicals, it is possible that construction of the proposed facility at the primary site could adversely affect property values at some nearby parcels. However, since abutting properties are commercial or industrial, any such impacts likely would be limited. In addition, the presence of intervening commercial/industrial properties likely would limit any adverse impact on the property value of nearby residences.

Finally, the Siting Board notes that the Massachusetts DFW has concluded that the design of the proposed facility appears to avoid impacts to box turtles and their habitat at the primary site. In addition, the record demonstrates that a number of authorities, including the NHESP, have concluded that deciduous forest is the preferred habitat of the box turtle, and that such habitat will be available to box turtles at the primary site. The record also shows that the area of deciduous forest at the primary site will be preserved, and that installing a fence according to DFW specifications will keep box turtles from entering areas of construction and, later, the proposed facility operations. The record also demonstrates that, despite some disagreement among authorities on the subject, the majority estimate that box turtles range a relatively small distance from home. Thus, the Siting Board concludes that construction and operation of the proposed facility at the primary site will not interfere with normal behavior of the box turtle in its natural habitat, assuming installation of appropriate fencing before the beginning of construction. The Siting Board anticipates that the Company will adhere to the recommendations of the DFW with respect to fencing to protect box turtles at the primary site.

Accordingly, the Siting Board finds that, with the installation of fencing to protect the box turtle, the environmental impacts of the proposed facility at the primary site would be minimized with respect to land use.

The record indicates that existing land uses surrounding the alternative site include a substantial amount of undeveloped land, as well as the sand and gravel operation. As with the primary site, the alternative site is located in an industrially zoned area; however, with the exception of the sand and gravel operation, the only industrial development in proximity to the site is limited light industrial. Since the site is 200 acres in size, a significant buffer can be provided in most directions between the proposed facility and surrounding land uses.

With respect to the utility interconnections, the alternative site would require an electric interconnect of 4.5 miles. The Siting Board notes that, given its length and the inclusion of the off-site overland segment, the electric interconnect may result in significant land use impacts. However, the land use impacts would be somewhat mitigated by the construction of 3.5 miles of the transmission line underground in a former railroad ROW.

BPD has asserted that the land use impacts of the proposed facility at the primary and the alternative sites are comparable. The Siting Board notes that the primary site offers the advantage of shorter utility easements, while the alternative site offers the advantage of a significant natural buffer. The land use impacts arising from the electric interconnect at the alternative site can be minimized using construction techniques and locating the line primarily in an existing ROW. However, while a man-made buffer such as landscaping or a berm can often minimize land use impacts to some degree, the land use impacts at the primary site cannot be minimized to the same extent as at the alternative site, which has the advantage of significant physical distance from the surrounding community. The Siting Board notes that the distance from the nearest residence to the proposed facility is similar at the primary and alternative sites, although the residential density in the area of the alternative site is less than the primary site.

Accordingly, the Siting Board finds that the alternative site would be slightly preferable to the primary site with respect to land use.

3. Cost

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 has been achieved between environmental impacts and cost. The Siting Board then compares the estimated costs of constructing and operating the proposed facilities at the primary and alternative sites.

The Company provided a confidential construction cost estimate for the proposed facility at the Agawam site based on its initial project design (Exh. BP-1C at 3). The Company stated that this cost estimate includes an estimate of the site specific and current information regarding: (1) construction costs, including EPC, construction interest, and construction management costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance of five percent; (4) site costs; and (5) other costs, including development costs and NOx offset costs (id.). The Company subsequently presented more detailed cost estimates which also were revised to show cost reductions stemming from updating of the pro formas originally submitted by the Company (Exhs. HO-RR-6; HO-V-4R; Tr. 13, at 108-112).

The Company also provided a confidential construction cost estimate for the proposed facility at the alternative site, and identified certain site-specific costs which the Company indicated would be higher at the alternative site than at the primary site (Exh. BP-1C at 4). The Company indicated that the total cost for the proposed facility would be approximately $10.725 million higher at the alternative site than at the primary site, primarily due to the need for two gas compressors which would not be required at Agawam; higher electric transmission line interconnect costs; greater gas pipeline costs; and greater costs for sewer and water supply interconnects (id.; HO-RR-66).

The Company asserted that the cost estimates it submitted for the proposed facility at both the primary site and at the alternative site are realistic for a facility of the proposed size and design (Exh. BP-1C at 3, 4). The Company further asserted that its estimates of EPC and interconnection costs reflect current information regarding labor markets, interest rates and equipment supplier prices, and are reasonable given the type of facility proposed (id.). In addition, the Company asserted that its contingency allowance, consistent with allowances for other facilities of this size, would cover for any unforeseen development and environmental mitigation costs, as well as capital cost escalation (id. at 3, 4-5).

BPD also identified the costs of several options to minimize further the environmental impacts associated with the proposed facility including: various water supply options and the use of dry cooling; gas supply arrangements to further minimize air quality impacts; and additional noise mitigation measures.

With respect to water supply options for the proposed facility at the primary site, the Company provided a cost comparison for its preferred option, i.e., the Agawam municipal system, and for two identified alternatives, (1) the Connecticut River option, which would require a new intake and supply line from the river to the proposed site, and (2) the groundwater well option, which would require new wells and supply line(s) to the site (Exh. HO-RR-71(supp.)). The Company submitted information showing that the combined capital costs and present value operating costs, in 1996 dollars, would be \$5.01 million for the preferred option, \$10.21 to \$10.56 million for the Connecticut River option, and \$4.57 to \$5.07 million for the groundwater well option (id.).

With respect to water supply options for the proposed facility at the alternative site, the Company indicated that it had been unable to obtain cost estimates for all of the water supply options at the Southwick site (Exh. HO-RR-70(supp.)). The Company stated, however, that the cost of drawing water from the City of Springfield, either directly or via the Southwick municipal system, would be the same as at the Agawam site (id.). The Company stated that the cost estimate for a well system at the Agawam site represents a reasonable cost estimate for water supply options relying on wellwater at the alternative site in Southwick (id.).

With respect to the use of dry cooling for the proposed facility at either the Agawam or the Southwick site, the Company estimated that costs in 1995 dollars of a dry cooling tower would exceed those for an evaporative cooling tower by \$4.4 million to \$5 million for construction, \$50,000 to \$100,000 for maintenance, and an additional unspecified amount to cover increased operating expenses due to capacity losses (Exh. HO-C-4).[232] The Company indicated that its estimates were based on a dry cooling tower design that would minimize overall project cost (id.). The estimates submitted by the Company indicated that

[232] The Company also provided an itemized comparison of capital costs for dry and wet cooling (Exh. HO-C-7).

dry cooling costs would be substantially greater than wet cooling costs, primarily due to incremental costs reflecting capacity and efficiency losses, higher maintenance costs, the additional cost of an air cooled condenser, and additional noise mitigation costs for dry cooling (id.; Exhs. HO-C-7; HO-E-62). In addition, the Company noted that, at the primary site, even its estimated expenditure of more than $1,000,000 for noise impact mitigation might not be enough to ensure that the proposed facility would meet MDEP/EFSB noise criteria (Exh. HO-C-4) (see Section III.B.2.d, above).

With respect to identified options for further noise mitigation at the primary site, the Company estimated a cost of $156,000 for extending the noise control barrier presently planned for three sides of the cooling tower to the tower's east side (Exh. HO-E-63). The Company asserted that the additional cost, which would provide noise reductions of 11 dBA and 10 dBA at the northeast and southeast property lines of the primary site, respectively, would not be appropriate due to non-residential land uses in those directions (id.).[233]

The Company also provided cost estimates for identified options for further noise mitigation at the nearest residential receptors, but contended that such options would be prohibitively expensive for benefits that would likely be imperceptible to residents (Exh. HO-E-64). The Company stated that it would cost: (1) at least $450,000 to eliminate the cooling tower as a significant noise source, a one dBA reduction; (2) at least $250,000 to install high-attenuation louvers on the ventilation air intake for the turbine building, an additional one dBA reduction; and (3) a minimum of $350,000 to double the size of the extra exhaust duct muffler and enclose the turbine exhaust duct and muffler in a masonry-walled building, an additional one dBA reduction (id.).

The record contains estimates of the overall costs of the proposed facility at the primary and alternative sites, including components of capital and operation costs which are site dependent, as well as cost information for measures to further minimize environmental

233 With respect to options and costs for noise mitigation at the primary and alternative sites, the Company stated that noise mitigation features at the alternative site would be comparable to those at the primary site (Exh. BP-1B at 8-53).

impacts at both sites. The Company has noted specific cost advantages of siting the proposed facility at the primary site.

Accordingly, 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 which site is preferable with respect to cost and whether an appropriate balance would be achieved among environmental impacts and cost.

With respect to comparison of the primary and alternative sites overall, the Company's analysis shows a total capital cost advantage of approximately $10.725 million for the primary site over the alternative site. The record demonstrates that the cost of constructing and operating the proposed facility at the primary site would be less than that at the alternative site. Accordingly, the Siting Board finds that the primary site is preferable to the alternative site with respect to cost.

4. Conclusions

In this section, the Siting Board reviews the consistency of the proposed facility with its overall review standard, which requires that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as between these environmental impacts and costs.

a. Conclusions on the Proposed Facility at the Primary Site

The Siting Board has found that, with the implementation of the conditions specified in Section III.B.2, above, the environmental impacts of the proposed facility at the primary site would be minimized with respect to water-related discharges, construction impacts on wetlands, visual impacts, traffic, safety, EMF, and land use. Further, in Section III.B.3, the Siting Board has found that BPD 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 cost.

The Siting Board has found that the Company has not established that the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, water supply, or noise. In Sections III.B.2.a, b, c and d, above, the Siting Board has identified five project design issues which require the Siting Board to evaluate tradeoffs among various environmental impacts or between environmental impacts and cost. These five issues are: (1) stack height, which requires the Siting Board to balance air quality and visual impacts; (2) level of firm gas transportation, which requires the Siting Board to balance air quality impacts and cost; (3) choice of cooling technologies, which requires the Siting Board to balance water supply impacts, noise impacts, and cost; (4) choice of water supply, which requires the Siting Board to balance water supply impacts, land use impacts, and cost; and (5) additional noise mitigation, which requires the Siting Board to balance noise impacts and cost. Thus, to complete its review, the Siting Board must address each of these issues in order to determine whether air quality impacts, water supply impacts, visual impacts and noise impacts would be minimized, consistent with minimizing cost and other environmental impacts.

The Company has proposed a 125-foot stack which, although less than the GEP stack height, would allow the Company to meet MDEP air quality permit requirements, including an emissions limit of 0.00193 lb/MMBtu for formaldehyde. The Company has also identified the option of using a 167.5-foot GEP stack, which would marginally reduce predicted ambient concentrations of criteria and non-criteria pollutants emitted from the proposed facility, as well as predicted ambient concentrations of air toxics. The Company also has identified visual impacts associated with construction of a 167.5-foot stack for the proposed facility. In Section III.B.2.c.iii, above, the Siting Board found that the visual impacts of the proposed facility would be minimized with a 125-foot stack.

The Company's local air modelling shows that, with either a 167.5 or 125 foot stack, combined background and facility ambient concentrations would be well below ambient standards, and that ambient concentrations emitted by the proposed facility would be below all established SILs. The 167.5 foot stack would have substantially greater visual impacts than a 125 foot stack, and would likely require additional construction and visual screening costs. Therefore, the Siting Board concludes that the marginal air quality benefits associated with a 167.5 GEP stack would not outweigh its additional visual impacts and costs.

Accordingly, the Siting Board finds that the construction of the proposed facility with a 125-foot stack would minimize environmental impacts, consistent with the minimization of cost.

With regard to the fuel supply for the proposed project, the Company has proposed to contract for firm gas transportation for 335 days per year, consistent with its request for an air permit that allows it to burn oil for up to 720 hours per year. The Company asserts that it needs the flexibility provided by the air permit to compete economically as a merchant power plant. However, the Company does not anticipate that the proposed facility would use oil for more than 100 hours per year in most years.

The Company has also identified the option of acquiring firm transportation of natural gas for 365 days per year, which likely would reduce the air quality impacts of the proposed project by enhancing the availability of natural gas for the proposed project. However, the Company contends that, while a 365-day firm transportation contract is a theoretical option for minimizing reliance on oil firing, such a contractual guarantee would increase the cost of power from the proposed project by $18.8 million/year, almost one cent/kWH.

Given the magnitude of this financial impact on the proposed project, the Siting Board agrees that the cost of a 365-day firm transportation contract would outweigh the marginal air quality benefits of completely eliminating the need for oil firing. Further, with respect to NOx, the pollutant for which control of emissions is particularly important given the classification of Massachusetts as non-attainment for O_3, the cost of firm transportation would significantly exceed the costs of purchasing additional NOx offsets for limited hours of oil firing. Thus, the record does not establish that a 365 day firm transportation contract is necessary to minimize environmental impacts consistent with the minimization of cost.

In reaching this conclusion, the Siting Board notes BPD's representation that oil-fired operation of the proposed facility would not exceed 100 hours in most years, and concludes that a 335 day firm transportation contract, combined with the flexibility to burn oil for 720 hours per year when necessary, is likely to be a cost-effective means of achieving air quality impacts well below those predicted by the Company's models based on thirty days of oil firing.[234] The Siting Board expects BPD to limit its use of oil to 100 hours or less in most years, and encourages it to modify its fuel supply arrangements if necessary to ensure that this goal is achieved. Accordingly, the Siting Board finds that the Company's plan to contract for firm gas transportation for 335 days per year would minimize environmental impacts, consistent with minimizing cost.

With respect to cooling technologies, the record demonstrates that overall project costs with dry cooling would be substantially greater than with evaporative cooling. The record also indicates that dry cooling would entail significant additional costs for noise mitigation, and that even with such mitigation, the proposed facility with dry cooling nonetheless may fail to meet MDEP noise requirements. In addition, the record demonstrates that water supply resources are adequate to meet the water supply needs of the proposed facility with evaporative cooling. Accordingly, the Siting Board finds that the use of evaporative cooling would minimize environmental impacts consistent with the minimization of costs.

In Section III.B.2.b.iii, above, the Siting Board expressed concern that BPD's reliance on its preferred water supply option would require the consumption of large quantities of potable water, with potential impacts on water resources, and noted that the groundwater well option might avoid such impacts. The record demonstrates that the cost of the groundwater well option is comparable to that of the Company's preferred option, although the preferred option has lower costs in the early years of the project. The record also demonstrates that the groundwater well option would require the construction of multiple wells and interconnects to these wells. The Siting Board therefore concludes that the groundwater well option likely would have greater land use impacts than the preferred option. Further, the recharge area for water resources supplying the preferred option would be greater than for those supplying the groundwater well option. In addition, there is the potential for the groundwater well option to adversely affect other water users or wetlands.

234 In addition, the Siting Board notes that a reduced level of oil-firing also would reduce water and traffic impacts.

Accordingly, the Siting Board finds that the Company's preferred water supply option would minimize environmental impacts consistent with the minimization of costs.

With regard to noise impacts, the Company has identified costs for further mitigation of the noise impacts of the proposed facility. These include costs for three options for reducing noise to the southwest of the facility, at the nearest residential receptor: (1) $450,000 for enclosure of the cooling tower; (2) $250,000 to reduce noise from the turbine building ventilation intake; and (3) $350,000 to enlarge and enclose the exhaust duct muffler. The Company also has indicated that a ground level barrier and an extension of the cooling tower fan deck barrier, which would reduce noise to the east of the facility, would cost $156,000.

The record demonstrates that the noise reductions that could be achieved at the nearest residence through additional noise mitigation are minimal, and that noise impacts at the nearest residence are within MDEP guidelines. The Siting Board therefore concludes that additional mitigation would not result in cost-effective noise reduction benefits to neighbors of the proposed facility. We note that the size and configuration of the site is a significant constraint in addressing noise impacts at the nearest residence, as the assumed location of the dominant noise source for that receptor, the cooling tower, already is located on the opposite, or northeast, edge of the site from the receptor. An expansion of the site and the facility layout toward the northeast, if possible, might have provided a more cost-effective means of reducing noise impacts at the nearest residence. In future cases, where site reconfiguration is a potentially cost-effective means of avoiding or minimizing noise impacts, applicants should include such options in their analysis of measures to adequately minimize such impacts.

BPD argues that the $156,000 cost of extending the cooling tower barriers to the east side of the facility cannot be justified, because the abutting land is not zoned for residential use. The record indicates that undeveloped land extends to the southeast, east and northeast for a half mile or more, and confirms that such land is not zoned for residential use. Further, a large abutting landholding in those directions is owned by WMECo, and currently is traversed by transmission lines located at distances of approximately 800 to 1,200 feet to the east and north of the cooling tower location. The record indicates that daytime increases in L_{90} noise exceeding the MDEP guideline would be limited to within approximately 450 to 750 feet of the facility property line.

However, the record does not indicate the area that would be affected by off-site nighttime noise increases approaching or exceeding the MDEP guideline. Further, the record contains little information on the owners and potential uses of vacant land located south, east and north of the abutting WMECo landholding, and within approximately one-half mile of the site. While this land is industrially zoned, the record demonstrates the potential for uses involving nighttime occupancy with a Special Permit. Therefore, the record neither establishes that nighttime noise increases would be ten dBA or less on the abutting WMECo land and vacant land to the south, east and north, nor establishes that possible nighttime noise increases in excess of ten dBA would be acceptable on such land.

The record indicates that extension of the ground level cooling tower barrier and fan deck to the east side of the cooling tower provides a likely cost-effective way to significantly reduce noise impacts of the proposed facility in that direction. In light of the potential for night-time occupancy of the abutting WMECo land and vacant land to the south, east and north, the Siting Board finds that the extension of the cooling tower barrier to the east side of the cooling tower likely would be necessary to minimize environmental impacts consistent with minimizing cost.[235] Consequently, the Siting Board requires BPD either to: (1) extend the ground level and fan deck barriers to the east side of the cooling tower; (2) develop alternative noise mitigation satisfactory to all property owners whose properties would otherwise experience increases in L_{90} noise exceeding MDEP guidelines; or (3) demonstrate, either to the Siting Board or to MDEP, that there would be no increases in L_{90} noise exceeding MDEP guidelines on any parcel where night-time occupancy is reasonably likely, given existing zoning restrictions and physical limitations on the development of those sites.

235 We note that measures to mitigate noise increases on such vacant land also would further mitigate noise increases on portions of the abutting WMECo landholding.

Accordingly, the Siting Board finds that, with the implementation of this condition, the noise impacts of the proposed facility would be minimized consistent with minimizing cost.

Based on its analysis of the five project design issues identified above, the Siting Board concludes that, with the implementation of the aforementioned condition, the air quality, water supply, visual, and noise impacts of the proposed facility at the primary site would be minimized consistent with the minimization of cost and other environmental impacts.

Therefore, the Siting Board finds that, with the implementation of the above condition and with the conditions set forth in Sections III.B.2, above, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost.

b. Comparison of the Primary and Alternative Sites

In Section III.B.2, above, the Siting Board has found that:

- the primary site would be slightly preferable to the alternative site with respect to air quality;
- on balance, the primary site would be slightly preferable to the alternative site with respect to water-related impacts;
- the alternative site would be preferable to the primary site with respect to visual impacts;
- the primary site would be comparable to the alternative site with respect to noise;
- that the primary site would be comparable to the alternative site respect to traffic impacts;
- the primary site would be comparable to the alternative site with respect to safety;
- the primary site would be preferable to the alternative site with respect to EMF impacts; and
- the alternative site would be slightly preferable to the primary site with respect to land use.

Accordingly, on balance, the Siting Board finds that the environmental impacts of the proposed facility at the primary and alternative sites are comparable.

The Siting Board also has found, in Section III.B.3, above, that the primary site would be preferable to the alternative site with respect to cost. Accordingly, the Siting Board finds that the primary site is preferable to the alternative site with respect to minimizing environmental impacts 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 the current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Section II.A, above, the Siting Board has found that the Company has established need for the proposed project. Further, in Sections II.B and II.C, above, 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, BPD will have established that its proposed project is reasonably likely to be a viable source of energy. In Sections III.A and III.B, above, the Siting Board has found that BPD has considered a reasonable range of practical facility siting alternatives, and that with implementation of the listed conditions relative to air quality, water-related impacts, visual impacts, noise and traffic, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost. Finally, in Section III.B, above, the Siting Board has found that the construction and operation of the proposed facility at the primary site is preferable to construction and operation of the proposed facility at the alternative site.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.C and III.B, above, and listed below, the construction and operation of the proposed project and ancillary facilities at the primary site will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section II.A.3, above, the Siting Board has found that there is a need in the Commonwealth for 252 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in the year in which economic efficiency benefits begin in the region. Further, in Sections III.A and III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs relating to air quality, water supply, water-related discharges, wetlands protection, noise, rare and endangered species, agricultural land preservation, and historical preservation. As evidenced by the above discussions and analyses, the proposed facility will be generally consistent with identified requirements under all such programs, although the facility as proposed by BPD would include a lower stack height than the MDEP-recognized GEP height and would result in property line noise impacts in excess of the MDEP ten-dBA guideline. The Siting Board agrees with the Company that exceptions to the above guidelines were reasonable options for the Company to consider based on offsetting environmental or cost considerations, and notes that the record suggests MDEP could consider such exceptions if adequate justification were provided.

In its review and balancing of overall environmental and cost considerations in Section III.B, above, the Siting Board has found that the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost, with (1) a less-than-GEP stack height, as proposed by BPD, and (2) BPD's compliance with the condition set forth in Section III.B.4 relating to noise impacts. The Siting Board therefore finds that the proposed project is likely to be consistent with various health, environmental protection and resource use and development policies of the Commonwealth which relate to the environmental impacts and cost of the Commonwealth's energy supply.

Accordingly, the Siting Board APPROVES the petition of Berkshire Power Development, Inc. to construct a 252-MW bulk generating facility and ancillary facilities in Agawam, Massachusetts subject to the following conditions.

(A) In order to establish that the project is likely to be constructed on schedule and will be able to perform as expected, the Siting Board requires BPD to provide it with a copy of a signed EPC turnkey contract between BPD and B&V/ABB Power Generation that is identical or similar in all significant provisions to the Term Sheet.

(B) In order to establish that the proposed project has access to the regional transmission system, the Siting Board requires BPD to provide the Siting Board with a copy of a signed interconnection agreement between BPD and NU.

(C) In order to establish that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, the Siting Board requires BPD to provide it with a copy of a signed O&M agreement between BPD and ABB O&M that is identical or similar in all significant provisions to the draft contract.

(D) In order to establish that BPD's fuel acquisition strategy reasonably ensures a low-cost reliable supply of energy over the planned life of the proposed project, the Siting Board requires BPD to provide it with signed contract(s) for 335 days or more of firm transportation from Wright (or a comparable location) to the proposed facility, or a comparable arrangement, such as firm deliverability based on transportation from Wright combined with downstream supplies.

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 shall 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:

(E) In order to mitigate CO_2 emissions, the Siting Board requires BPD to provide CO_2 offsets through an annual seedling distribution program or a comparable tree planting or forestation program, or combination thereof, so as to attain an annual offset level equivalent to 0.385 percent of annual facility emissions within five years of facility start-up and 0.550 percent of annual facility emissions within 20 years of facility start-up.

(F) In order to minimize water supply impacts, the Siting Board directs the Company to work in conjunction with the City of Springfield to identify and as appropriate implement measures to ensure the long-term ability of the Springfield municipal system, including Cobble Mountain, to supply BPD and other customers.

(G) In order to minimize visual impacts, the Siting Board directs the Company to provide reasonable off-site shrub and tree plantings to help screen the proposed facility from roadways and properties on or near the intersection of Losito Road and Shoemaker Lane, and on or near Suffield Street and the southern portion of Shoemaker Lane, and at other locations within one mile of the proposed facility, as may be requested by property owners or appropriate municipal officials; consistent with the directives set forth in Section III.B.2.c.iii, above.

(H) In order to minimize traffic impacts, the Siting Board requires BPD, in consultation with the Town of Agawam, to develop and implement a traffic mitigation plan which includes scheduling to avoid peak travel periods, route modification, or other appropriate measures to minimize construction-related traffic impacts at the Suffield Street/Shoemaker Street intersection during actual intersection peak periods.

(I) In order to alleviate public concern, the Siting Board directs the Company to monitor fogging and icing in the vicinity of the proposed facility and, as necessary, establish a plan in cooperation with local officials to alert motorists and residents concerning any project-related fogging or icing episodes affecting public safety.

(J) In order to minimize noise impacts consistent with minimizing cost, the Siting Board requires BPD either to: (1) extend the cooling tower and fan deck barriers to the east side of the cooling tower; (2) develop alternative noise mitigation satisfactory to all property owners whose properties would otherwise experience increases in L_{90} noise exceeding MDEP guidelines; or (3) demonstrate, either to the Siting Board or to MDEP, that there would be no increases in L_{90} noise exceeding MDEP guidelines on any parcel where night-time occupancy is reasonably likely, given existing zoning restrictions and physical limitations on the development of those sites.

Because issues addressed in this decision relative to this facility are subject to change over time, construction of the proposed generating facility and ancillary facilities must be commenced within three years of the date of this CONDITIONAL APPROVAL.

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
Hearing Officer

Dated this 19th day of June, 1996

TABLE 1

RANGE OF REGIONAL NEED CASES - SUMMER
(COMPANY ANALYSIS)
1999 - 2001

1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(2,200)	(1,372)	(2,056)
1993 Celt	B	(2,437)	(1,610)	(2,294)
1993 Celt	L	(2,655)	(1,828)	(2,512)
1994 Initial CELT	H	(737)	40	(593)
1994 Initial CELT	B	(975)	(147)	(831)
1994 Initial CELT	L	(1,193)	(365)	(1,049)
1995 CELT	H	42	870	186
1995 CELT	B	(196)	632	(52)
1995 CELT	L	(414)	414	(270)
1994 Normalized	H	(1,753)	(925)	(1,609)
1994 Normalized	B	(1,991)	(1,163)	(1,847)
1994 Normalized	L	(2,208)	(1,381)	(2,065)
1994 2.5%	L	(2,414)		

2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(3,245)	(2,118)	(2,945)
1993 Celt	B	(3,529)	(2,403)	(3,229)
1993 Celt	L	(3,786)	(2,659)	(3,486)
1994 Initial CELT	H	(1,697)	(570)	(1,396)
1994 Initial CELT	B	(1,981)	(854)	(1,681)
1994 Initial CELT	L	(2,237)	(1,110)	(1,937)
1995 CELT	H	(761)	366	(461)
1995 CELT	B	(1,045)	82	(745)
1995 CELT	L	(1,302)	(175)	(1,002)
1994 Normalized	H	(2,590)	(1,463)	(2,290)
1994 Normalized	B	(2,874)	(1,747)	(2,574)
1994 Normalized	L	(3,131)	(2,004)	(2,831)
1994 2.5%	L	(3,548)		

2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(4,617)	(2,962)	(3,789)
1993 Celt	B	(4,960)	(3,305)	(4,131)
1993 Celt	L	(5,246)	(3,609)	(4,435)
1994 Initial CELT	H	(2,747)	(1092)	(1,919)
1994 Initial CELT	B	(3.089)	(1,434)	(2,261)
1994 Initial CELT	L	(3,394)	(1,738)	(2,565)
1995 CELT	H	(1,665)	(10)	(837)
1995 CELT	B	(2,008)	(352)	(1,179)
1995 CELT	L	(2,312)	(656)	(1,483)
1994 Normalized	H	(3,516)	(1,861)	(2,688)
1994 Normalized	B	(3,85[illegible])	(2,203)	(3,030)
1994 Normalized	L	(4,163)	(2,507)	(3,334)
1994 2.5%	L	(4,983)		

Source: Exhs. BP-RG-1, exh. 3; HO-RR-29

TABLE 2

RANGE OF REGIONAL NEED CASES - WINTER
(COMPANY ANALYSIS)
1998/1999 - 2000/2001

1998/1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(2,099)	(1,537)	(2,099)
1993 Celt	B	(2,318)	(1,756)	(2,,318)
1993 Celt	L	(2,525)	(1,963)	(2,525)
1994 Initial CELT	H	250	812	250
1994 Initial CELT	B	30	592	30
1994 Initial CELT	L	(176)	386	(176)
1995 CELT	H	22	739	22
1995 CELT	B	(198)	520	(198)
1995 CELT	L	(404)	158	(404)
1994 Final	H	177	739	177
1994 Final	B	(42)	520	(42)
1994 Final	L	(249)	313	(249)
1994 2.5%	L	(1200)		

1999/2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(3,378)	(2,502)	(3,207)
1993 Celt	B	(3,649)	(2,773)	(3,478)
1993 Celt	L	(3,900)	(3,024)	(3,729)
1994 Initial CELT	H	(999)	(123)	(828)
1994 Initial CELT	B	(1,270)	(394)	(1099)
1994 Initial CELT	L	(1,521)	(645)	(1,350)
1995 CELT	H	(978)	(102)	(807)
1995 CELT	B	(1,249)	(373)	(1,078)
1995 CELT	L	(1,500)	(624)	(1,329)
1994 2.5%	L	(2,598)		

2000 - 2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 Celt	H	(4,067)	(2,868)	(3,717)
1993 Celt	B	(4,391)	(3,192)	(4,042)
1993 Celt	L	(4,687)	(3,488)	(4,337)
1994 Initial CELT	H	(1,400)	(201)	(1,051)
1994 Initial CELT	B	(1,725)	(526)	(1,375)
1994 Initial CELT	L	(2,021)	(822)	(1,671)
1995 CELT	H	(1,400)	(201)	(1,051)
1995 CELT	B	(1,725)	(526)	(1,375)
1995 CELT	L	(2,021)	(822)	(1,671)
1994 2.5%	L	(3,447)		

Source: BP-RG-1, exh. 4; HO-RR-29

TABLE 3

RANGR OF REGIONAL NEED CASES - <u>SUMMER</u>
(STAFF ANALYSIS)
1999 - 2001

1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1994 Initial CELT	H	(737)	90	(371)
1994 Initial CELT	B	(975)	(147)	(631)
1994 Initial CELT	L	(1,193)	(365)	(827)
1995 CELT	H	42	870	408
1995 CELT	B	(196)	632	170
1995 CELT	L	(414)	414	(48)
1994 Normalizied	H	(1,753)	(925)	(1,387)
1994 Normalized	B	(1,991)	(1,163)	(1,625)
1994 Normalized	L	(2,208)	(1,381)	(1,843)

2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1994 Initial CELT	H	(1,697)	(570)	(1,174)
1994 Initial CELT	B	(1,981)	(854)	(1,459)
1994 Initial CELT	L	(2,237)	(1,110)	(1,715)
1995 CELT	H	(761)	366	(239)
1995 CELT	B	(1,045)	82	(523)
1995 CELT	L	(1,302)	(175)	(780)
1994 Normalizied	H	(2,590)	(1,463)	(2,068)
1994 Normalized	B	(2,874)	(1,747)	(2,352)
1994 Normalized	L	(3,131)	(2,004)	(2,609)

2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1994 Initial CELT	H	(2,747)	(1,092)	(1,679)
1994 Initial CELT	B	(3,089)	(1,434)	(2,039)
1994 Initial CELT	L	(3,394)	(1,738)	(2,343)
1995 CELT	H	(1,665)	(10)	(615)
1995 CELT	B	(2,008)	(352)	(959)
1995 CELT	L	(2,312)	(656)	(1,261)
1994 Normalizied	H	(3,516)	(1,861)	(2,466)
1994 Normalized	B	(3,859)	(2,203)	(2,808)
1994 Normalized	L	(4,163)	(2,507)	(3,112)

Source: BP-RG-1, exhs. 3, 15; HO-RR-29

TABLE 4

RANGE OF REGIONAL NEED CASES - WINTER
(STAFF ANALYSIS)
1998/1999 - 2000/2001

1998/1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	22	739	265
1995 CELT	B	(198)	520	45
1995 CELT	L	(404)	158	(161)

1999 - 2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	(978)	(102)	(564)
1995 CELT	B	(1,249)	(373)	(835)
1995 CELT	L	(1,500)	(624)	(1,086)

2000 - 2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	(1,400)	(201)	(808)
1995 CELT	B	(1,725)	(526)	(1,132)
1995 CELT	L	(2,021)	(822)	(1,428)

Source: Exhs. BP-RG-1, exh 4, 16; HO-RR-29

TABLE 5

RANGE OF MASS NEED CASES - SUMMER
(COMPANY ANALYSIS)
1999

1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 CELT	H	(1,860)	(1,566)	(1,815)
1993 CELT	B	(1,899)	(1,605)	(1,854)
1993 CELT	L	(1,996)	(1,702)	(1,951)
1994 Initial CELT	H	(1,446)	(1,152)	(1,401)
1994 Initial CELT	B	(1,485)	(1,191)	(1,440)
1994 Initial CELT	L	(1,581)	(1,287)	(1,536)
1995 CELT	H	(1,083)	(789)	(1.038)
1995 CELT	B	(1,121)	(827)	(1,076)
1995 CELT	L	(1,218)	(924)	(1,173)
1994 2.5%	L	(1,635)		

Source: Exxh. HO-RR-29

TABLE 6
RANGE OF MASS NEED CASES - WINTER
(COMPANY ANALYSIS)
1998/1999 - 2000/2001

1998/1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 CELT	H	38	193	38
1993 CELT	B	0	155	0
1993 CELT	L	(95)	60	(95)
1994 Initial CELT	H	362	517	362
1994 Initial CELT	B	324	479	324
1994 Initial CELT	L	229	384	229
1995 CELT	H	256	411	256
1995 CELT	B	218	373	218
1995 CELT	L	123	278	123
1994 2.5%	L	(21)		
1994 Final CELT	H	324	479	324
1994 Final CELT	B	286	441	286
1994 Final CELT	L	191	346	191

1999/2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 CELT	H	(494)	(177)	(443)
1993 CELT	B	(539)	(222)	(488)
1993 CELT	L	(649)	(332)	(598)
1994 Initial CELT	H	(219)	98	(168)
1994 Initial CELT	B	(263)	54	(212)
1994 Initial CELT	L	(373)	(56)	(322)
1995 CELT	H	(216)	101	(165)
1995 CELT	B	(260)	57	(209)
1995 CELT	L	(371)	(54)	(320)
1994 2.5%	L	(586)		

2000/2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1993 CELT	H	(708)	(332)	(637)
1993 CELT	B	(759)	(383)	(688)
1993 CELT	L	(889)	(513)	(818)
1994 Initial CELT	H	(1,013)	(637)	(942)
1994 Initial CELT	B	(1,065)	(689)	(994)
1994 Initial CELT	L	(1,195)	(819)	(1,124)
1995 CELT	H	(1,020)	(644)	(949)
1995 CELT	B	(1,072)	(696)	(1,001)
1995 CELT	L	(1,202)	(826)	(1,131)
1994 2.5%	L	(851)		

Source: Exh. HO-RR-29

TABLE 7

RANGE OF MASS NEED CASES - SUMMER
(STAFF ANALYSIS)
1999

1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1994 Initial CELT	H	(1,446)	(1,152)	(1,253)
1994 Initial CELT	B	(1,485)	(1,191)	(1,292)
1994 Initial CELT	L	(1,581)	(1,287)	(1,388)
1995 CELT	H	(1,083)	(789)	(890)
1995 CELT	B	(1,121)	(827)	(928)
1995 CELT	L	(1,218)	(924)	(1,025)

Source: Exh. HO-RR-29

TABLE 8

RANGE OF MASS NEED CASES - WINTER
(STAFF ANALYSIS)
1998/1999 - 2000/2001

1998/1999

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	256	411	404
1995 CELT	B	218	373	366
1995 CELT	L	123	278	271

1999 - 2000

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	(216)	101	(17)
1995 CELT	B	(260)	57	(61)
1995 CELT	L	(371)	(54)	(172)

2000 - 2001

Demand Case	DSM	Low Supply	High Supply	Base Supply
1995 CELT	H	(1,020)	(644)	(801)
1995 CELT	B	(1,072)	(696)	(853)
1995 CELT	L	(1,202)	(826)	(983)

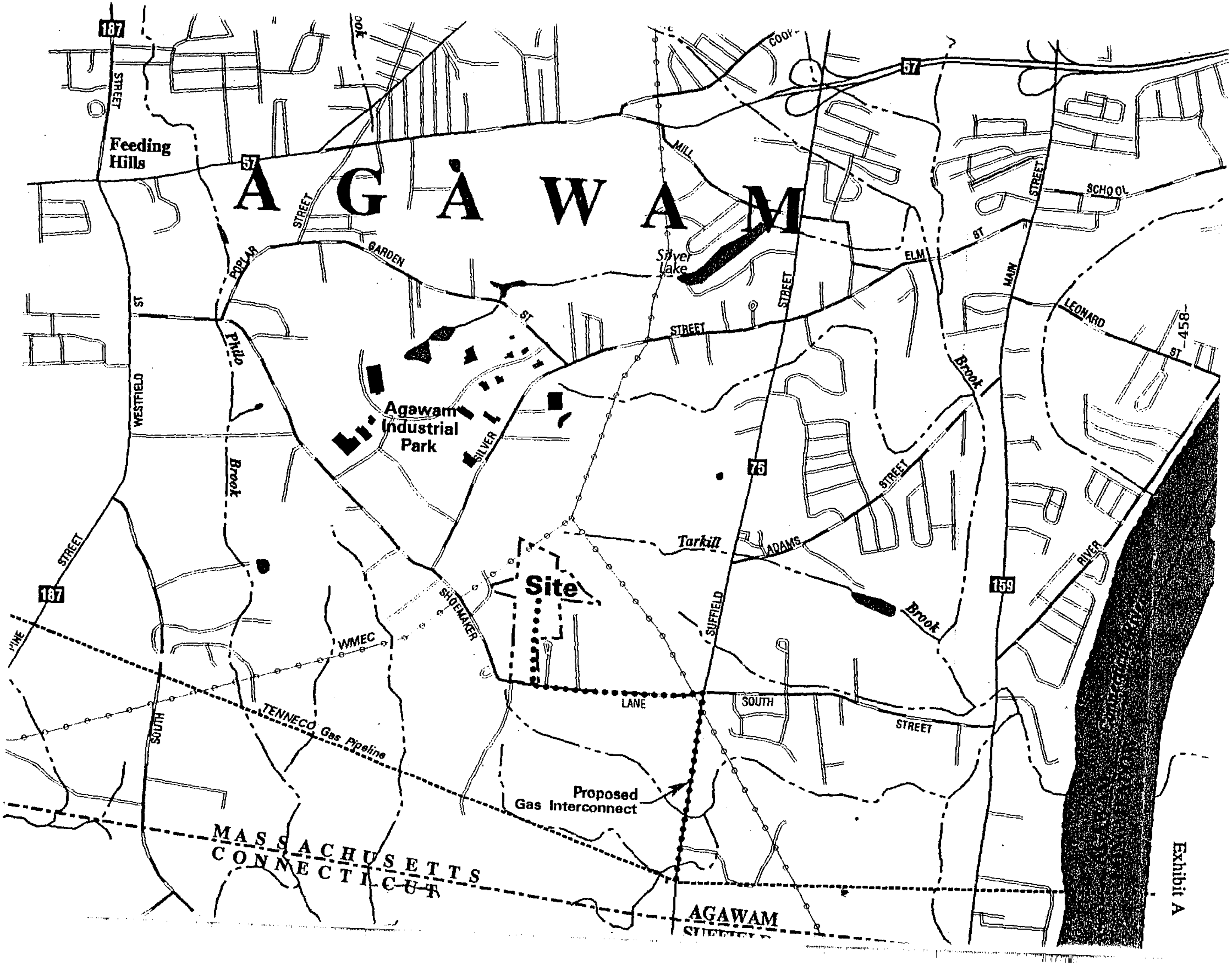
Source: HO-RR-29

TABLE 9

EMISSIONS SAVINGS WITH DISPATCH OF PROPOSED PROJECT
(TONS)

	1993 DISPATCH SCENARO			UPDATED 1994 DISPATCH SCENARO		
	1999-2018	1999-2003	1999	1999-2018	1999-2003	1999
SOx	6,832	4,948	1,051	16,578	12,382	7,060
NOx	1,105	749	163	2,850	1,923	1,086
VOCs	81	34	9	178	76	35
CO	330	239	66	981	589	354
PM-10	359	313	63	1,137	867	541
CO2	1,560,366	840,446	186,344	3,117,844	1,818,570	973,745

Sources: Exhs. BP-1A at att. 3-32; HO-RR-44 (red).



AGAWAM
Feeding Hills
187
57
75
159
WESTFIELD ST
STREET
SOUTH
PINE
POPLAR ST
GARDEN ST
STREET
Philo Brook
Agawam Industrial Park
SILVER STREET
SHOEMAKER LANE
Site
WMEC
TENNECO Gas Pipeline
Proposed Gas Interconnect
SUFFIELD STREET
SOUTH STREET
Tarkill Brook
ADAMS STREET
Silver Lake
MILL
COOP
ELM ST
MAIN STREET
SCHOOL
LEONARD ST
RIVER
Brook
MASSACHUSETTS
CONNECTICUT
AGAWAM

Exhibit A

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 91-102A

ACTION BY CONSENT

This "Action by Consent" is made pursuant to authority granted the Chairman of the Energy Facilities Siting Board ("Siting Board") under 980 C.M.R. § 2.06. Section 2.06 provides the Siting Board with authority to render a decision "when it would be a hardship to the public welfare to defer the decision until the next scheduled meeting of the [Siting Board]." 980 C.M.R. § 2.06(1).

On August 16, 1995, the Siting Board, by a majority vote, conditionally approved the petition of Altresco Lynn, Inc. ("Altresco Petition") to construct a bulk generating facility and ancillary facilities in the City of Lynn, Massachusetts (Docket No. EFSB 91-102A). An appeal of that Final Decision was taken by Boston Edison Company and a joint appeal was taken by the City of Revere and Point of Pines Beach Association, Inc. (Docket Nos. SJC-95-0469 and SJC-95-0481, respectively).

On July 25, 1996, Altresco Lynn, Inc. formally withdrew the Altresco Petition, thereby mooting the Siting Board's August 1995 Final Decision. As (1) the appeals are pending and (2) the next scheduled meeting of the Siting Board will not take place until September 26, 1996, we find that it would be a hardship to the public welfare to defer a decision to rescind the August 1995 conditional approval.

Now, therefore, the Siting Board by unanimous written consent hereby rescinds the conditional approval granted Altresco Lynn, Inc. in Docket No. EFSB 91-102A on

August 16, 1995 to construct a bulk generating facility and ancillary facilities in the City of Lynn, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe

John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

Mary Clark Webster

Mary Clark Webster
Commissioner
Department of Public Utilities

Janet Gail Besser

Janet Gail Besser
Commissioner
Department of Public Utilities

David L. O'Connor
for David A. Tibbetts
Director of the Department of
Economic Development

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

August 16, 1996

Effective Date

August 16, 1995 to construct a bulk generating facility and ancillary facilities in the City of Lynn, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

Mary Clark Webster
Commissioner
Department of Public Utilities

Janet Gail Besser
Commissioner
Department of Public Utilities

D L O'C
David L. O'Connor
for David A. Tibbetts
Director of the Department of
Economic Development

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

August 16, 1996
Effective Date

August 16, 1995 to construct a bulk generating facility and ancillary facilities in the City of Lynn, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe
Chairman
Energy Facilities Siting Board/
Department of Public Utilities

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Commissioner
Department of Public Utilities

Janet Gail Besser
Commissioner
Department of Public Utilities

David L. O'Connor
for David A. Tibbetts
Director of the Department of
Economic Development

Sonia W. Hamel

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

August 16, 1996

Effective Date

August 16, 1995 to construct a bulk generating facility and ancillary facilities in the City of Lynn, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

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Department of Public Utilities

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for David A. Tibbetts
Director of the Department of
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Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

August 16, 1996
Effective Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Silver City Energy Limited Partnership for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	))))	EFSB 91-100

ACTION BY CONSENT

This "Action by Consent" is made pursuant to authority granted the Chairman of the Energy Facilities Siting Board ("Siting Board") under 980 C.M.R. § 2.06. Section 2.06 provides the Siting Board with authority to render a decision "when it would be a hardship to the public welfare to defer the decision until the next scheduled meeting of the [Siting Board]." 980 C.M.R. § 2.06(1).

On June 15, 1994, the Siting Board by a unanimous vote conditionally approved the petition of Silver City Energy Limited Partnership ("SCE Petition") to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts (Docket No. EFSB 91-100). Appeals of that Final Decision were taken by the Office of the Attorney General, and Silver City Energy Limited Partnership, and a joint appeal was taken by the Conservation Law Foundation and the Massachusetts Public Interest Research Group (Docket Nos. SJC-94-0460, SJC-94-0463, and SJC-94-0464, respectively).

On June 28, 1996, Silver City Energy Limited Partnership formally withdrew the SCE Petition, thereby mooting the Siting Board's June 1994 Final Decision. As (1) the three appeals are pending and currently subject to Motions to Stay, filed by the Siting Board, and (2) there are no meetings of the Siting Board scheduled or planned for scheduling in the near future, we find that it would be a hardship to the public welfare to defer a decision to rescind the June 15, 1994 conditional approval.

Now, therefore, the Siting Board by unanimous written consent do hereby rescind the conditional approval granted Silver City Energy Limited Partnership in Docket No. EFSB

91-100 on June 15, 1994 to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe
John B. Howe
Chairman
Energy Facilities Siting Board/
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Secretary of Economic Affairs

Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

William Sargent
Public Member

8/22/96
Effective Date

91-100 on June 15, 1994 to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

John B. Howe
Chairman
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Department of Public Utilities

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Department of Public Utilities

Janet Gail Besser
Commissioner
Department of Public Utilities

David L. O'Connor / Diana Jeong

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Sonia Hamel
for Trudy Coxe
Secretary of Environmental Affairs

Joseph Faherty
Public Member

William Sargent
Public Member

8/22/96

Effective Date

91-100 on June 15, 1994 to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts.

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8/22/96

Effective Date

91-100 on June 15, 1994 to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts.

This Action by Consent may be executed in any number of counterparts, each of which shall be an original, but all of which constitute one agreement, and shall be dated and become effective when the copies bearing all of the signatures of the Siting Board members are received by the Chairman. 980 C.M.R. § 2.06(2).

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91-100 on June 15, 1994 to construct a bulk generating facility and ancillary facilities in the City of Taunton, Massachusetts.

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Joseph Faherty
Public Member

Bill Sargent
William Sargent
Public Member

8/22/96
Effective Date

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