Decision and Orders

Massachusetts Energy Facilities Siting Board

VOLUME 1

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petitions of Boston Edison Company for Approval of Its 1990 Long Range Forecast of Electric Requirements and Resources and for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 90-12/90-12A (Phase II)

FINAL DECISION

Robert W. Ritchie
Hearing Officer
August 5, 1993

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TABLES:

The Energy Facilities Siting Board[1] hereby CONDITIONALLY APPROVES Boston Edison Company's primary site in Weymouth, Massachusetts for possible future use as a site for a 306 megawatt, gas-fired, bulk electric generating facility and ancillary facilities.

I. INTRODUCTION

A. Summary of Proposed Project and Facilities

Boston Edison Company ("BECo" or "Company") has proposed to construct the Edgar Energy Park Project ("Edgar project"), a 306 megawatt ("MW") combined cycle generating unit to be fueled by natural gas with possible dual fuel capabilities[2] on a

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1/ Pursuant to Chapter 141 of the Acts of 1992 ("Reorganization Act"), effective September 1, 1992, the functions of the Energy Facilities Siting Council ("Siting Council" or "EFSC") were merged into the Department of Public Utilities ("Department" or "DPU"). Reorganization Act, § 55. Under the Reorganization Act, facility siting cases are now reviewed and decided by a newly created Energy Facilities Siting Board ("Siting Board"). (§§ 9, 15). The Reorganization Act provides that all facility petitions before the Siting Board, regardless of when they were filed, will be reviewed consistent with all orders, rules and regulations duly made, all approvals duly granted, and all legal and decisional precedents established by the Siting Council until superseded, revised, rescinded or cancelled in accordance with law by the Siting Board. Id., §46.

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

The terms Siting Council and Siting Board will be used throughout this decision as appropriate to the circumstances being discussed.

2/ BECO had originally proposed that the facility would utilize natural gas for seven months and fuel oil for up to five months, then later proposed to utilize natural gas for 320 days and No. 2 distillate fuel oil for up to 45 days (Exhs. BE-6, 56-acre parcel of land located in the Town of Weymouth ("Weymouth"), Massachusetts ("primary site" or "Edgar site").[3] BECo proposed that natural gas would be supplied to the facility via a new 24-inch, 10.7 mile pipeline to be constructed by Algonquin Gas Transmission Company ("Algonquin") which would extend from the termination of Algonquin's existing line in Avon, Massachusetts to the primary site (Exh. HO-E-102, pp. 1, 2).[4] Distillate fuel oil, if required for the operation of the facility, will be delivered to the site via barge and stored in an existing tank (Exh. BE-6, p. 2-8). Electric power generated by the proposed facility will be supplied for transmission through interconnection to the existing 115 kilovolt ("kV") switchyard at the primary site (id., p. 2-9). This

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sec. 6, BE-48, AQ-3 through AQ-10). More recently, in a submittal to the Massachusetts Department of Environmental Protection ("MDEP"), the Company recommended that in addition to the above fuel mix, still another fuel mix be considered as an alternative for the project -- use of natural gas for 365 days, with oil as a back-up fuel for emergency periods only (Exh. HO-RR-93). See Section II.D.1.a.(1)(a), below.

3/ At the time BECo filed its original proposal to construct the facility on May 1, 1990, the Company estimated a completion date of November 1993 for the project (Exh. BE-6, p. 2-9). By letters dated January 31 and February 14, 1992, BECo notified the Siting Council that it was revising its projected in-service date to January 1, 1996. On May 1, 1992, BECo notified the Siting Council that the Company decided to defer construction of the facility indefinitely, but requested that the Siting Council continue the review of, and issue a decision approving, the company's resource plan and the siting and environmental aspects of its proposal. See Section I.B., below.

4/ Algonquin filed an application with the Federal Energy Regulatory Commission ("FERC") on January 16, 1991, for a certificate of convenience and necessity to construct and operate this natural gas pipeline (Tr. 14, p. 12; see FERC Docket CP91-952-000). As a result of BECo's decision to defer construction of the Edgar project, Algonquin submitted a notice to FERC on December 1, 1992, withdrawing its application concerning the natural gas pipeline. The Siting Board takes administrative notice of this withdrawal. In its withdrawal notice, Algonquin stated that it would refile the application when the timing of the proposed facility is more definite.

interconnection will require new underground 115 kV lines to the switchyard (id.). Off-site transmission of electric power from the switchyard will make use of existing lines and will not require establishment of new off-site transmission or distribution facilities, nor require off-site reconductoring of existing lines (id.).

Other major components of the proposed facility at the primary site include two combustion turbine generators with dual fuel capability; two heat recovery steam generators ("HRSG") with selective catalytic reduction ("SCR") units;[5] a single steam turbine generator; a steam surface condenser; a demineralization system consisting of several storage tanks, including a 10,000 gallon bulk acid storage tank, a 20,000 gallon bulk caustic storage tank, a 200,000 gallon demineralized water storage tank; a circulating water intake structure; a circulating water discharge structure; clean and dirty lube oil tanks; and main and unit auxiliary transformers (id., pp. 2-4, 2-5, 2-7 to 2-9; Exh. BE-120, App. B). The proposed facility would also include two emission stacks 245 feet in height and two 100-foot high auxiliary boiler stacks (Exhs. BE-6, pp. 7-6 and 7-7; HO-E-50). The Company expects to pursue use of potable water from the City of Quincy as its water supply for the proposed facility at the primary site (Exh. BE-120, p. ii).

The primary site is located in an industrially zoned area in Weymouth (Exhs. BE-6, p. 2-1; BE-59, p. 5.9-2). The site is bounded by the Weymouth Fore River on the north, south, and west sides (Exh. BE-6, p. 2-2). The east side of the site is partially bounded at its northern end by Kings Cove; at the center by Monatiquot Street and its adjacent residential area; and at the south end by Mill Cove (id.). The surrounding land area is predominantly densely populated (id.).

5/ BECo filed a new air emissions control plan with the MDEP on November 13, 1992 which contains a number of alternative fuel proposals that would not utilize SCR (Exh. HO-RR-93). See Section II.D.1.a.(1)(a), below.

In accordance with G. L. c. 164, §69J, BECo presented an alternative site for the proposed project in the Town of Uxbridge ("Uxbridge"), Massachusetts ("alternative site" or "Ironstone site") (id., p. 5-1).[6] The alternative site proposed by BECo is a 300-acre parcel consisting of agricultural and undeveloped land and is located two miles southwest of the center of Uxbridge (id., pp. 5-10 and 5-11).[7] The site is bordered on the south by the Massachusetts/Rhode Island state line and by residential development along the north, east, and west site boundaries (id., p. 5-10).

In addition to requiring the same major components that would be constructed at the Weymouth site, the Uxbridge site would require construction of additional components. Due to the inland nature of the site, a closed loop heat rejection system will be required at the site, necessitating the construction of a mechanical draft cooling tower, a cooling tower make-up water pumphouse, and a water pipeline connecting the pumphouse to the cooling tower (id., pp. 5-21, 5-23, 5-24, 5-26). Additional facilities required on and off-site would include a new 345 kV switchyard with transmission connections and improvements to the existing 345 kV transmission system, and a natural gas pipeline to connect with Algonquin's natural gas pipeline located approximately one-quarter mile north of the northern site boundary (id., pp. 5-21, 5-23, and 5-26; Tr. 56 at 143).

B. Procedural History

On May 1, 1990, the Company filed with the Siting Council its 1990 long-range demand forecast and supply plan, and a

6/ Prior to September 1, 1992, when the functions of the Siting Council were merged into the Department of Public Utilities, this requirement was found in G.L. c. 164, §69I.

7/ The site is zoned for agricultural uses, recreational and residential development, and development of airports, drive-in theaters and cemeteries (Exh. BE-6, p. 5-11).

proposal to construct the 306 MW gas-fired electric generating facility and ancillary facilities (Exhs. BE-1, BE-2, BE-3, BE-6).

On June 22, 1990, the Siting Council and the Department issued a joint notice of adjudication and public hearing concerning this proceeding and three related petitions filed with the DPU by BECo as follows: (1) a petition for a zoning exemption to site the proposed generating facility at the Edgar site (D.P.U. 90-106); (2) a petition for approval of investments in a new subsidiary to construct and operate the Edgar project (D.P.U. 90-117); and (3) a petition for preapproval of the Edgar project construction costs and the Edgar project power purchase agreement pursuant to 220 C.M.R. 9.00 et seq. (D.P.U. 90-118). On July 27, 1990, the Siting Council and DPU signed a joint Memorandum of Understanding ("MOU") which set forth the procedures and a tentative schedule to be followed for these interrelated proceedings.[8]

The Siting Council held a public hearing in Uxbridge on July 23, 1990, and, with the DPU, held a joint public hearing in Weymouth on July 24, 1990. BECo provided notice of the public hearings and adjudication as directed by the Hearing Officers.

A notice of intervention was filed by the Office of the Attorney General of the Commonwealth ("Attorney General") on July 6, 1990. Motions to intervene subsequently were filed by the Conservation Law Foundation ("CLF"), Distrigas of Massachusetts Corporation ("DOMAC"), the Energy Consortium, the Massachusetts Public Interest Research Group ("MASSPIRG"), Nancy Zerfoss, Weymouth, the Weymouth Board of Public Health ("WBH"), the Weymouth Department of Public Works, Richard and Suzanne Dauphin, the East Braintree Civic Association ("EBCA"), the Blackstone River and Canal Commission, the Blackstone River Valley National Heritage Corridor ("BRVNHC") Commission, Uxbridge, the Uxbridge Planning Board, Uxbridge Parents for Clean

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8/ The Department approved BECo's motions to withdraw all three of these proceedings on July 15, 1992.

Air and Water, Daniel Richardson, and the South Uxbridge Community Association. Motions to participate as interested persons were filed by Richard and Jacquelyn Aloise, Robert and Leslie Sahagian, the Boston Gas Company, Cogen Technologies, Save the Bay, Inc., and the New England Cogeneration Association ("NECA").

On August 16, 1990, NECA filed a motion to substitute its petition to participate as an interested person with a petition to intervene. On August 30, 1990, Nancy Zerfoss submitted a letter clarifying her motion to intervene. Ms. Zerfoss stated that the intent of her original motion was to request intervenor status on behalf of the citizen group, Weymouth Against the Edgar Revitalization ("WATER"). On September 14, 1990, DOMAC requested that its motion to intervene be considered instead as a motion to participate as an interested person. At a prehearing conference on September 14, 1990, all motions for intervention and all motions for interested person status were granted (September 14, 1990 Prehearing Conference, Tr. pp. 6-19).

The Siting Council held 49 evidentiary hearings on the demand forecast, supply plan, and Edgar project beginning on February 22, 1991, and ending on June 21, 1991. During the course of the hearings, BECo presented 12 witnesses: Robert J. Cuomo, manager of forecasting and market analysis at BECo, who testified regarding energy and peak demand forecasts; Gregory R. Sullivan, manager of the distribution and planning section of the electrical engineering and station operations department at BECo, who testified concerning the need for transmission and distribution facilities; Johannes H. Baumhauer, principal engineer at BECo, who testified regarding the Performance Management Study; William P. Killgoar, manager of energy resource planning and forecasting at BECo, who testified regarding BECo's long-range integrated resource plan; Paul D. Vaitkus, head of supply planning at BECo, who testified regarding the supply-side planning portion of the BECo Resource Plan; Richard S. Hahn, vice-president of marketing at BECo, who testified concerning the

BECo Resource Plan and Pilgrim Analysis; Kathleen A. Kelly, manager of demand-side planning, monitoring and evaluation at BECo, who testified regarding demand-side planning; John F. Carlin, manager of fossil fuel planning, procurement, regulation and performance at BECo, who testified concerning fuel supply; Cameron H. Daley, senior vice-president for power supply at BECo, who testified regarding project approach and least cost analysis; John J. Reed, president of Reed Consulting Group, who testified concerning the power purchase agreement between BECo and Edgar Electric Energy Corporation ("EEEC"); Douglas C. Schmidt, project manager for engineering and licensing for the Edgar project, who testified regarding project design and costs, water supply and alternative sites; and Dr. Lillian N. Morgenstern, principal environmental planner at BECo, who testified concerning potential environmental impacts of the Edgar project and alternative sites.

Weymouth presented the testimony of 13 witnesses: John F. Buckley, water and sewer superintendent for Weymouth, who testified regarding water supply; James J. Pescatore, engineer for Camp, Dresser & McKee, who testified concerning water supply; William C. Woodward, conservation administrator for Weymouth, who presented testimony regarding water quality; Jeffrey R. Coates, inspector of buildings for Weymouth, who presented testimony concerning zoning issues; Robert S. Knorr, deputy director of the Division of Environmental Health Assessment at the Massachusetts Department of Public Health, who testified regarding health-related issues; Jane Gallahue, Commissioner of Public Health in the City of Quincy, who testified concerning health issues; Mary McAdams, Chairperson of the Weymouth Board of Health, who testified regarding health issues; Karen M. Durgin, chemicals management and surveillance officer for the WBH, who testified concerning hazardous conditions at the primary site; Maura Kelly, member of the WBH, who presented testimony regarding elevated cancer rates in the area around the primary site; Robert Hedlund, State Senator for Weymouth, who testified concerning health problems; Robert A. Cerasoli, State Representative for

Weymouth and Quincy, who presented testimony regarding health problems; David Jenkins, a former member of the Weymouth Local Assessment Committee, who testified regarding existing health problems in Weymouth; and Brian J. McDonald, vice chairman of the Weymouth Board of Selectmen, who presented testimony concerning health issues.

The Attorney General presented one witness: Susan Geller, an economist for the Attorney General, who testified regarding the Company's Supply Plan.

CLF presented two witnesses: Paul L. Chernick, president of Resource Insight, Inc., who testified concerning demand-side analysis and the Company's Supply Plan; and Susan E. Coakley, technical coordinator for CLF, who testified regarding demand-side analysis.

Uxbridge presented five witnesses: Russell Cohen, Blackstone River coordinator for the Massachusetts Department of Fisheries, Wildlife and Environmental Law Enforcement, who testified concerning water supply and water quality issues at the alternative site; Noelle F. Lewis, water quality specialist for Save the Bay, Inc., who testified regarding water quality issues at the alternative site; James Cormier, former chairman of the Growth Study Committee for Uxbridge, who testified concerning land use issues; James Pepper, executive director of the BRVNHC Commission, and Douglas M. Reynolds, historian for the BRVNHC Commission, who both testified on issues related to the alternative site in Uxbridge.

The Hearing Officers entered 569 exhibits into the record, primarily consisting of responses to information requests and record requests. The Attorney General entered 161 exhibits into the record. BECo entered 125 exhibits into the record. MASSPIRG entered 73 exhibits into the record. NECA entered 40 exhibits into the record. The Energy Consortium entered one exhibit into the record. Uxbridge entered 101 exhibits into the record. WATER entered 52 exhibits into the record. Weymouth entered 26 exhibits into the record.

Initial briefs of the Attorney General ("AG Initial Brief"), CLF, MASSPIRG, NECA and Uxbridge ("Uxbridge Initial Brief") were filed on July 26, 1991. The New England Council, the Associated Industries of Massachusetts and the Greater Boston Chamber of Commerce ("Business Associations")[9] filed a joint brief on July 26, 1991. In lieu of a brief, on July 26, 1991, Weymouth filed an agreement entered into with BECo which addresses commitments made by the Company with respect to water supply, a health study, and other issues ("Weymouth/BECo agreement"); and a statement of position of the Town's Board of Public Works (Exhs. WEY-21 and WEY-22). WATER filed two initial briefs, one related to water use issues ("WATER Initial Brief") on August 2, 1991, and one related to health issues ("Carey Brief") on August 5, 1991. BECo's initial brief ("BECo Initial Brief") was filed on August 16, 1991.

The Attorney General, MASSPIRG, NECA and WATER[10] filed reply briefs on September 3, 1991. Weymouth filed a statement in lieu of a reply brief on September 3, 1991. BECo's reply brief ("BECo Reply Brief") was filed on September 13, 1991.

Due to the extensive record compiled in the docket, the Hearing Officers, in a memorandum to all parties dated September 30, 1991, determined that the decision in this proceeding should be separated into two phases. In that memorandum, the Hearing Officers determined that the Phase I decision would address issues associated with the Company's demand forecast and resource need. More specifically, the memorandum stated that the Phase I decision would include:

> (1) an analysis of the Company's demand forecasting methodology, an examination of its projections of existing and planned resources, and the integration of

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9/ On June 17, 1991, the Business Associations filed a motion, subsequently granted, to participate as interested persons for the sole purpose of filing a brief.

10/ WATER submitted two reply briefs, one concerning water issues and one concerning health issues.

> those factors to achieve various levels of system reliability; (2) a determination of the level of resource need; and (3) a determination of the adequacy of the Company's supply plan in the short run.

Hearing Officers' Memorandum dated September 30, 1991, p. 2.

The Hearing Officers' memorandum further indicated that the Phase II decision would address: (1) the adequacy of the Company's supply plan in the long run; (2) the least-cost nature of the Company's supply plan, including consideration of the Edgar project and other resource options available to serve the resource need identified in Phase I; (3) the Company's site selection process; and (4) the cost, environmental and reliability impacts of the proposed facilities at both the primary and alternative sites.

On April 10, 1992, the Siting Council issued a final decision in Phase I of this matter, approving BECo's 1990 demand forecast, and finding that the Company could anticipate a capacity surplus of 149 MW in 1996 and 120 MW in 1997, and that its base case supply plan was adequate to meet its projected requirements in the short run. Boston Edison Company (Phase I), 24 DOMSC 125 (1992) ("1992 BECo Decision (Phase I)").

On May 1, 1992, BECo filed a motion with the Hearing Officers stating that the Company had decided to defer construction of the Edgar project and requesting that the Siting Council continue the review of, and issue a decision approving, the Company's resource plan and the siting and environmental aspects of this proceeding. In that motion, BECo asserted that the request was made on the basis of the Company's intention to retain the Edgar project as a contingency resource to be relied upon in the future when the need for additional capacity would arise.

At a Procedural Conference on May 11, 1992, and by memorandum dated May 12, 1992, the Hearing Officers asked all parties to submit written comments regarding the Company's request by June 8, 1992.[11]

On May 20, 1992, comments were submitted on behalf of EBCA, and on June 1, 1992, comments were filed by WATER. On June 8, 1992, comments were filed by BECo ("BECo Comments"), NECA, and Weymouth. On the same date, the Attorney General, CLF, and MASSPIRG filed a joint memorandum in opposition to BECo's request.

In a Procedural Order dated July 10, 1992 ("Site Banking Procedural Order"), the Hearing Officer deferred review of the Company's resource plan to its next filing (Site Banking Procedural Order, at 21),[12] and granted the Company's request to continue the review of the siting and environmental impacts

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11/ The Hearing Officers requested that the parties address, at a minimum, the following questions:

> (1) What legal authority does the Siting Council have to issue a decision only on the siting and environmental aspects of a facility project whose construction has been indefinitely deferred? Do any other jurisdictions issue comparable "site-banking" findings?
>
> (2) If such authority does exist, why should the Siting Council decide to proceed with Phase II as a matter of policy?
>
> (3) What should be the precise scope of any further proceedings in Phase II at this time, e.g., which resource plan issues, if any, should be reviewed; should the Siting Council determine whether Edgar Station is a superior site to the Ironstone site or just determine whether Edgar Station is an acceptable site?
>
> (4) If the Siting Council does issue "site-banking" findings this year, what conditions on such findings would be appropriate?

12/ In its comments, BECo maintained that further review of supply planning issues would be best deferred to the Company's next filing (BECo Comments, at 15).

of the project (id., at 1-18).[13] With respect to project

13/ In the Site Banking Procedural Order, at 8, the Hearing Officer stated that no language in either the Siting Council's enabling statute or its regulations prohibits the issuance of conditional approvals, pending a final review to ensure the completion of all such conditions. (In fact, G.L. c. 164, §69J specifically provided the Siting Council, and now the Siting Board, with the authority to issue conditional approvals. See Section I.C. below.) The Hearing Officer also noted that no language in either the statute or regulations explicitly limits "the subject matter that may be conditioned or the length of time for compliance with a condition imposed in a decision." (Site Banking Procedural Order, at 8). The Hearing Officer noted further that:

> site banking of energy generating resources could shorten the final review of projects and thus make more projects eligible to meet a near term resource need. Site banking could thus provide more resources from which utilities might select the least-cost, least-environmental resources available. In this manner, site banking can better enable the Siting Council to meet its statutory mandate to "ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." (id., at 9).

The Hearing Officer then concluded that the Siting Council had the authority consistent with G.L. 164, §69H to issue a site-banking decision (id., at 10).

After determining that the Siting Council had the legal authority to proceed with a site-banking review, the Hearing Officer stated that requests for site-banking reviews must be evaluated on a case-by-case basis, and then explained why such a review would be appropriate in this case (id., at 16-19). The Hearing Officer stated that the proposed project had "been under development for several years and had reached a relatively mature stage of design", and thus was "sufficiently defined to allow a detailed examination of the environmental impacts at the proposed and alternative sites" (id., at 17). The Hearing Officer noted that a substantial record had already been developed in this proceeding on the majority of the issues pertinent to a site-banking decision and, "[c]onsequently, the potential benefits associated with proceeding with a siting review and a conditional decision in this proceeding warrant such an approach" (id., at 18). See Section I.D., below, for a discussion and analysis of the scope of this site-banking review.

viability issues, the Hearing Officer agreed with the Company that any unresolved issues would be addressed in the future, but indicated that, to the extent that the Company could provide specific plans and contracts, the Siting Council could review such plans and contracts in this proceeding (id., at 22).[14]

The Company later indicated that, due to the deferral of the Edgar project, it would not be seeking findings on project viability in this proceeding (Tr. 50, p. 7). BECo further stated that it would present more specific evidence on project viability when the Company proceeds with its need case for the project. (id.).

Nine additional hearings were held on siting, costs, and environmental issues in Phase II beginning on August 24, 1992, and ending on October 1, 1992. During the course of this round of hearings, BECo presented two witnesses, Douglas C. Schmidt and Lillian N. Morgenstern, both of whom testified regarding project design and costs, water supply, alternative sites, and potential environmental impacts at the primary and alternative sites. WATER presented one witness, Robert Loring, member of WATER, who testified concerning an exhibit introduced by WATER.

The Hearing Officers entered 78 additional exhibits into the record in Phase II of this proceeding, primarily consisting of responses to information requests and record requests. The Attorney General entered six exhibits into the record in Phase II. BECo entered two exhibits into the record in Phase II. WATER entered 37 exhibits into the record in Phase II. Weymouth entered 32 exhibits into the record in Phase II. The EBCA entered 7 exhibits into the record in Phase II.

The initial site banking briefs of BECo ("BECo Site Banking Brief"), the Attorney General ("AG Site Banking Brief"), Weymouth ("Weymouth Site Banking Brief"), and WATER ("WATER Site

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14/ On July 20, 1992, WATER filed a Motion for Reconsideration of the Site Banking Procedural Order. The motion was denied in a Procedural Order issued by the Hearing Officers on August 24, 1992.

Banking Brief") were filed on November 13, 1992. The reply site banking briefs of BECo ("BECo Site Banking Reply Brief") and WATER ("WATER Site Banking Reply Brief") were filed on November 20, 1992, while the Attorney General filed a letter in lieu of a reply brief on November 20, 1992. Uxbridge filed a letter in lieu of a reply brief on November 24, 1992.

C. Jurisdiction

BECo's petition to construct a bulk generating facility was filed in accordance with G.L. c. 164, §§ 69H and 69J, which required the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and pursuant to G.L. c. 164, § 69I, which required electric companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.[15]

As a generating facility with a design capacity of approximately 306 MW, BECo'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, BECo's proposals to construct a switchyard at the alternative site, and electric transmission lines and other structures at both sites fall within the third definition of "facility" set forth in G.L. c. 164, § 69G, which states that a facility is:

15/ Pursuant to Chapter 141 of the Acts of 1992, which reorganized the Siting Council into the Siting Board, this requirement now appears in G.L. c. 164, §69J.

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

In accordance with G.L. c. 164, §§ 69H and 69J, before approving an application to construct facilities, the Siting Council required applicants to justify generating facility proposals in four phases. First, the Siting Council required the applicant to show that additional energy resources are needed. New England Power Company, 21 DOMSC 325, 333 (1991) ("1991 NEPCO Decision"); Boston Edison Company/Massachusetts Water Resources Authority, 19 DOMSC 1, 8 (1989) ("BECo/MWRA"); Altresco-Pittsfield, 17 DOMSC 351, 358 (1988); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA"). Second, the Siting Council required 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. Id. Third, the Siting Council required the applicant to show that its project is viable. MASSPOWER, 20 DOMSC 301, 310 (1990). Finally, the Siting Council required the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. 1991 NEPCO Decision, 21 DOMSC at 333; BECo/MWRA, 19 DOMSC at 8; Altresco-Pittsfield, 17 DOMSC at 358; NEA, 16 DOMSC at 343. As noted above, pursuant to the Reorganization Act, all facility petitions before the Siting Board, including the instant one, will be reviewed consistent with all legal and decisional precedents established by the Siting Council until such standards are superseded, revised, rescinded, or cancelled in accordance with law by the Siting Board. Reorganization Act, §46.

As noted in Section I.B. above, after BECo notified the Siting Council that the Company decided to defer the construction of the Edgar project, the Hearing Officer issued a Procedural

Order deferring review of the Company's supply plan, and granting the Company's request to continue the review of the siting and environmental aspects of the project (Site Banking Procedural Order, at 1-18, 21).[16] In the Site Banking Procedural Order, the Hearing Officer concluded that the Siting Council had the authority to issue a conditional site-banking decision (id., at 10).

The Siting Board notes that G.L. c. 164, §69J specifically provides the Siting Board with the authority to issue conditional approvals. As noted by the Hearing Officer in the Site Banking Procedural Order, there is no language in the enabling statute or regulations limiting the subject matter that may be conditioned or the length of time for compliance with a condition imposed in a decision. See G.L. c. 164, §§69H, 69I, and 69J.

The Siting Board further notes that in Massachusetts Municipal Wholesale Electric Company v. Massachusetts Energy Facilities Siting Council, 411 Mass. 183, 194 (1991), the Supreme Judicial Court stated:

> "An agency's powers are shaped by its organic statute taken as a whole and need not necessarily be traced to specific words." Commonwealth v. Cerveny, 373 Mass. 345, 354 (1977). "Powers granted include those necessarily or reasonably implied." Grocery Manufacturers of America, Inc. v. Department of Public Health, 379 Mass. 70, 75 (1979).

The Supreme Judicial Court has also stated that an administrative agency has "considerable leeway in interpreting a statute it is charged with enforcing." Id. Thus, given the express authority to issue conditional approvals pursuant to G.L. c. 164, § 69J, the Siting Board agrees with the Hearing Officer that the issuance of a conditional site-banking decision valid for an extended period of time, subject to a later review of

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16/ As stated in Section I.B. above, the issues of need and project viability will be deferred until the Company's next filing.

compliance with stated conditions and to a subsequent balancing of environmental impacts, cost, and reliability issues prior to a final decision, is a power that is reasonably implied by our enabling statute (Site Banking Procedural Order, at 10).

The Siting Board also agrees with the Hearing Officer that site banking of energy generating resources could potentially reduce the length of time needed for a final review of a project proposal, and thus make more projects eligible to meet a near-term resource need. In situations where a short-term need for energy resources has been established, site banking could make more resources available from which utilities could select the least-cost, least-environmental impact resource. Thus, site banking may better enable the Siting Board to meet its statutory mandate to "ensure that the Commonwealth has a necessary energy supply with a minimum impact on the environment at the lowest possible cost." G.L. c. 164, §69H. See Site Banking Procedural Order, at 9.

Therefore, we reaffirm the decision of the Hearing Officer that the Siting Board has the inherent authority consistent with G.L. c. 164, §§69H and 69J to issue a conditional site banking decision for an extended period of time.[17]

17/ Having determined that the Siting Board has the authority to issue site-banking decisions, we also agree with the Hearing Officer's decision in the Site Banking Procedural Order that requests for site banking reviews must be evaluated on a case-by-case basis (Site Banking Procedural Order, at 16-19). In the instant case, as the Hearing Officer noted, the project under review has been under development for several years and the facility design is sufficiently defined to allow a detailed review of the site selection process and the environmental impacts at the proposed and alternative sites. Prior to the issuance of the Site-Banking Procedural Order, the parties had been involved in 49 days of hearings, a number of which pertained to the site selection, cost, and environmental issues addressed in this decision. Therefore, we reaffirm the decision of the Hearing Officer that the Edgar project is sufficiently mature to proceed with a site banking review in this case.

D. Scope of Review

This is the first case in which the Siting Board or its predecessor, the Siting Council, has reviewed a request for a site banking approval. In their briefs, the Company, the Attorney General, and WATER addressed the scope of this decision, and the potential effect of findings made by the Siting Board herein. In this Section, the Siting Board reviews these arguments and specifies the detailed scope of review of this decision.

1. Positions of the Parties

a. The Company's Arguments

The Company acknowledged that the site banking approval that it seeks would not constitute a final approval of the Edgar project (BECo Site-Banking Brief, p. 9). The Company further stated that the findings should be subject to modification based upon significant new information, such as changes in the project or changes in the applicable law (BECo Comments, pp. 16-17). BECo also suggested that parties should be required to notify the Siting Board of any new information that would "materially affect" one of the Siting Board's findings (id.). The Company noted that the Siting Board will retain jurisdiction over this project until final approval is given and construction begins (BECo Site Banking Brief, p. 60). Finally, the Company argued that this decision should include "permission" for other state environmental agencies to "proceed with their licensing activities" and issue permits for the facility (id., p. 10).[18]

BECo responded to the Attorney General's arguments regarding the uncertainty of future regulatory, technological, economic, and other conditions by stating that such uncertainty

18/ G.L. c. 164, § 69J provides that "no state agency shall issue a construction permit for [a] facility unless the petition to construct such facility has been approved by the [siting] board and the facility conforms with [the Company's] long-range forecast."

could appropriately be addressed by the Siting Board in its decision (BECo Site Banking Reply Brief, p. 2). The Company noted that the Site Banking Procedural Order recognized the potential for regulatory change, but that order noted that the Siting Council (now Siting Board) would retain jurisdiction over all aspects of a facility until a final decision is issued and, thus, the Siting Board would be able to revisit any aspects of a site banking decision affected by such changes (BECo Site Banking Reply Brief, p. 3).

b. The Intervenors' Arguments

The Attorney General urged the Siting Board to deny the Company's request for site-banking approval because of potentially significant changes in the applicable laws, regulations, and project elements, such as environmental control technology and fuel and water supplies, between now and the projected date of need for the proposed facility. (AG Site-Banking Brief, p. 8).[19] The Attorney General also urged that, in the event the Siting Board grants any part of the Company's request, the Siting Board's review should be limited to "only those facts known with some certainty today and that appear likely to be stable over the decade" (AG Site Banking Brief, p. 14). The Attorney General requested that any assumptions made

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19/ The Attorney General asserted that the date of need would be 1998 or later (AG Site Banking Brief, p. 8). Since BECo indefinitely delayed the project, the Company has made no assertion regarding the date of need for the Edgar project, or under what circumstances it would propose to move forward with the final review of the Edgar project. The Siting Board notes that in BECo's recent draft initial filing made with the DPU pursuant to the Integrated Resource Management process ("BECo Draft IRM Filing"), the Company identified the first year of capacity need as 2002 (BECo Draft IRM Filing, Volume C, p. 2) However, the Siting Board recognizes that numerous combinations of circumstances could lead BECo to identify a need for the project prior to that date. The Siting Board makes no determination regarding the likely year of need for the proposed project in this decision.

by the Siting Board in its review must be very clearly and explicitly set forth (id., pp. 9, 14). The Attorney General argued that any decision should be conditioned on the results of a subsequent review conducted prior to, but "reasonably contemporaneous in time with, construction." (id., p. 14). During that review, the Attorney General argued, the Company must affirmatively prove that there have been no significant changes in the facts and law upon which all earlier approvals were based, and the Siting Board must review all deferred facts, new facts, and then-current law (id.).

WATER argued that the Company's request for site banking approval should be denied on the grounds that the Company failed to provide sufficient information for the Siting Board to make a determination because of the lack of an approved water supply at the Edgar site (WATER Initial Site Banking Brief, pp. 1-2).[20]

In response to BECo's request that other state agencies should be permitted to issue permits based on this decision, WATER argued that because this decision is not a final approval of the project, other agencies may not issue final permits for the project[21] (WATER Site Banking Reply Brief, p. 2).

WATER also argued that any decision to allow banking of the Edgar site should not be open ended, but should have an expiration date (id., pp. 6, 7). WATER suggested that the expiration date should be concurrent with the date that the Secretary of Environmental Affairs ("Secretary") must revisit the Certificate on the Environmental Impact Report ("EIR") to determine whether a five-year lapse of time significantly

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20/ For a further discussion of WATER's argument regarding the water supply issue, see Section II.D.1.e below.

21/ WATER argued that this decision does not constitute a final decision because the Siting Board has not evaluated the need for the facility, nor has it determined the viability of the project (WATER Site Banking Reply Brief, p. 2). Referring to the Company's brief, WATER also pointed out that BECo acknowledged in its Site Banking Brief that the requested site banking approval is not a final approval of the project (id.).

increases the environmental consequences of the project and warrants resubmission of an Environmental Notification Form ("ENF"), rescoping, supplementary documentation, or another EIR (id.).[22]

2. Discussion and Analysis

BECo and WATER are both correct in asserting that this decision does not constitute a final approval of the Edgar project. This decision is a conditional approval of limited, site-related issues only, pending a final review to ensure the completion of all conditions set forth in this decision and to review and make findings on other statutory and regulatory requirements not addressed herein. As the Company stated, all findings in this decision are subject to modification based upon new information, such as significant changes in the project,[23] site conditions, or the applicable law. As stated in the Site Banking Procedural Order, the Siting Board

> ... retains jurisdiction over all aspects of a facility until a final decision is issued, thereby enabling us [the Board] to revisit any environmental requirements or other project elements which may change. Clearly, the final balancing between need, cost and environmental impact could not take place until all elements of the proposal are in place (at 8-9).

22/ Massachusetts Environmental Policy Act ("MEPA") regulations require this action by the Secretary if more than five years have elapsed after the filing of the final EIR and construction of the project has not begun (see 301 C.M.R. 11.17). The Final EIR for this project was filed in February 1992 (Exh. HO-RR-57B).

23/ All findings in this decision are based on the project design proposed by BECo in its filing, and as described in the record of this proceeding, namely a 306 MW combined cycle generating unit to be fueled primarily by natural gas and up to 45 days on No. 2 distillate fuel oil. Should the Company propose any changes in the design of the project, all findings affected by such changes may be revisited and modified as deemed appropriate by the Siting Board at such time as BECo wishes to petition for final approval.

See Eastern Energy Corporation, 22 DOMSC 188, 312, 411 (1991), ("EEC"); West Lynn Cogeneration, 22 DOMSC 1, 76, 110 (1991) ("West Lynn"); MASSPOWER, 20 DOMSC 301, 370, 405 (1990). This language, which the Siting Board hereby reaffirms, adequately addresses the concerns raised by the Attorney General concerning potential changes that could occur in the applicable law, environmental control technology, fuel and water supplies, and any other changes relevant to the findings contained herein.

The Siting Board notes that the other concerns of the Attorney General are similarly addressed, insofar as the Company is required to submit another filing with the Siting Board before the project can be constructed. If the Company submits such a filing, there will be another review of the project by the Siting Board at that time. The Company will have the burden of demonstrating that there have been no significant changes in the facts and law upon which the findings in this decision were based. The Siting Board will review all new facts and information, as well as the law in effect at that time, to determine whether significant changes have occurred that would modify any of the findings contained herein. Thus, the Siting Board is confident that a conditional decision of limited scope in this matter at this time will not allow the Company to construct a facility at some point in the future which does not meet all then applicable laws and standards.

In addition to the review of any changes in design, site conditions, applicable law, or other relevant facts, and a showing that all conditions specified herein are addressed (see Section III), final approval of the Edgar project will require a showing of need on reliability or economic efficiency grounds. The Company will also have to compare its proposed project with other energy resource alternatives, as required by G. L. c. 164, § 69J (see City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)), and BECo will have to establish that the project is viable.[24] Further, the Siting Board will conduct its final balancing of need, cost and environmental impacts in accordance with G.L. c. 164, §§ 69H and 69J before a final decision on the project is made (see Section II.A., below).

In regard to the Attorney General's proposal that the Board's current review be limited to "only those facts known with some certainty today and that appear to be likely to be stable over the decade," the Siting Board notes that such a standard is vague and impractical. In this and all future reviews, the Siting Board will examine every relevant issue that has been adequately developed in the record. Where there is a strong likelihood of changed circumstances or a need for additional analysis, the Siting Board has the ability to place conditions on findings in this decision in order to ensure that any such changes will be adequately addressed in the future should they occur.

In regard to BECo's argument that this decision should include "permission" for other state agencies to issue permits, G.L. c. 164, § 69J provides that "no state agency shall issue a construction permit for [a] facility unless the petition to construct such facility has been approved by the board and the facility conforms with [the Company's] long-range forecast." In this case, neither of the two statutory criteria have been met which would allow another state agency to issue a construction permit. As discussed above, this decision is not a full and final approval, or even a conditional approval, to construct the Edgar facility, nor does this decision contain a finding that the facility conforms to an approved long-range Company forecast. Therefore, the Siting Board finds that other agencies are

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24/ BECo, of course, will be required to comply with all applicable Siting Board statutes, regulations and standards of review in effect at the time of its filing.

prohibited from issuing a construction permit for BECo's proposed facility until these statutory requirements are met.[25]

Finally, in response to WATER's argument that a site banking decision should have an expiration date, the Siting Board does not agree. As explained above, there is no language in our statute or regulations which limits the length of time a conditional decision may remain in effect. Imposing such a limit would defeat the purpose of a site banking review, which is to ensure a greater selection of resources from which utilities may select the least-cost, least-environmental impact resource to meet a near-term resource need.

In response to WATER's concerns regarding an "open-ended" site banking decision, the Siting Board reiterates that BECo will not be able to construct its proposed project at the primary site unless and until it has received a final Siting Board decision regarding all matters not addressed herein and compliance with all conditions contained herein, and either has established that no significant changes[26] have occurred with respect to environmental impacts and costs at the primary site, or has addressed such changes and demonstrated that environmental impacts have been minimized at the primary site and an appropriate balance has been achieved among conflicting environmental concerns and among environmental impacts, cost and

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25/ The Siting Board notes that until the above requirements of c. 164, § 69J are met, other agencies have the discretion consistent with their own statutes and regulations to proceed in various ways including, but not limited to, the rejection or conditional approval of permit applications or deferral of consideration of such applications until final project plans are submitted. See Procedural Order, EFSB 90-12/12A, August 24, 1992, p. 6, n. 4.

26/ The Siting Board notes that examples of significant changes that could affect the findings in this decision include, but are not limited to, amendments to relevant law, changes in facility design or site characteristics, or advancements in technology.

reliability.[27] Furthermore, as noted above, this decision does not allow other state agencies to issue final construction permits for the project. This provides added assurance that all relevant facts and law will be fully considered by the appropriate regulatory authorities at the time the Company decides to proceed with its project.

The Siting Board is sympathetic to the concerns of a community which hosts a "banked" site due to the uncertainty regarding whether or when such a site will be developed. Nevertheless, it is our view that, aside from this uncertainty, the most significant risk associated with a site banking decision is borne by the applicant. If, in fact, circumstances change sufficiently to render a site unacceptable between the time a site banking decision is issued and the time that need is established for the project, the applicant's final petition for approval of the project will be rejected.[28] Further, if the applicant is unable to establish that the proposed project is superior to alternative resources available to meet the identified need, the final petition for approval of the project will likewise be rejected.[29] Thus, the Siting Board believes

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27/ It is specifically for this reason that this decision is fundamentally different than a certificate on a final EIR, which is a final determination.

28/ The Siting Board notes that at such time as the applicant seeks such final approval, the local community will have a full and fair opportunity to address any changed circumstances affecting the environmental impacts or costs at the site.

29/ As noted above, a showing that the proposed project is superior to alternative energy resources will be required if the Company chooses to seek final approval of the Edgar project. The Siting Board notes that when a project proponent is a utility, such as BECo, the DPU routinely reviews the applicant's long-range forecast and supply plan. See 220 C.M.R. 10.00. These reviews will ensure that alternative resources within the utility's control will be adequately considered and compared to the Edgar project.

that the benefits associated with site banking, as discussed above, significantly outweigh any associated risks.

Accordingly, with respect to the scope of this decision, the Siting Board will address herein (1) the Company's site selection process, and (2) the environmental impacts and costs of the proposed facilities at both the primary and alternative sites. As explained further in Section II.A below, after making a final determination on the site selection process and after reviewing and balancing the environmental impacts and costs at both sites, the Siting Board will make a final decision as to which of the two sites is superior. Should the Company choose to pursue this project further, all issues that the Company will be required to address in its next filing with the Siting Board will relate solely to the site approved in this decision.

II. ANALYSIS OF THE PROPOSED AND ALTERNATIVE FACILITIES

A. Standard of Review

The Siting Board has a statutory mandate 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 and J. Further, G. L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Council required the petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

1. Site Selection Process

In order to determine whether a facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Council required a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Berkshire Gas Company, 25 DOMSC 1, 48 (1992) ("1992 Berkshire Decision"); Berkshire Gas Company, 23 DOMSC 294, 323 (1991) ("1991 Berkshire Decision"); Enron Power, 23 DOMSC 1, 115 (1991) ("Enron"); EEC, 22 DOMSC at 314; West Lynn, 22 DOMSC at 77 (1991); 1991 NEPCO Decision, 21 DOMSC at, 48 (1991); MASSPOWER, 20 DOMSC at 371; Berkshire Gas Company (Phase II), 20 DOMSC 109, 148 (1990) ("1990 Berkshire Decision"); Altresco-Pittsfield, 17 DOMSC at 387 (1988); NEA, 16 DOMSC, 381-409 (1987). In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Council typically required the proponent to meet a two-prong 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. 1992 Berkshire Decision, 25 DOMSC at 48; 1991 Berkshire Decision, 23 DOMSC at 323; Enron, 23 DOMSC at 121; EEC, 22 DOMSC at 122-123; West Lynn, 22 DOMSC at 77; 1991 NEPCo Decision, 21 DOMSC at 376; MASSPOWER, 20 DOMSC at 373-374, 382; 1990 Berkshire Decision, 20 DOMSC at 148-149, 151-156. Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity.[30] 1992 Berkshire Decision, 25 DOMSC at 49; 1991 Berkshire Decision, 23 DOMSC at 324; Enron, 23 DOMSC at 122; EEC, 22 DOMSC at 123; West Lynn, 22 DOMSC at 77-78; 1991 NEPCo Decision, 21 DOMSC at 376-377; MASSPOWER, 20 DOMSC at 371-372; 1990 Berkshire Decision, 20 DOMSC at 148; NEA, 16 DOMSC at 381-409.[31]

The Siting Board notes that proposed sites or routes located in the coastal zone as defined under the Massachusetts Coastal Zone Management ("CZM") program and the Coastal Zone Management Act, 16 U.S.C. § 1453, are subject to additional regulatory requirements.[32] The Siting Board is the designated

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

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

32/ In the instant case, the primary site proposed by BECo is located in the coastal zone as defined by the CZM Program and the CZM Act and regulations, 16 U.S.C. § 1453 (Exh. BE-6, p. 5-1).

energy facilities siting agency under the CZM program pursuant to 980 CMR 9.01ff. These regulations implement the CZM program as adopted by the Secretary of Environmental Affairs under G.L.c. 21A, §§ 2, 3, and 4.

Under the Siting Board's Coastal Zone Facility Site Selection, Evaluation, and Assessment regulations, when a facility is proposed for coastal siting, the petitioner must "propose, evaluate and compare at least one alternative site." 980 CMR 9.02(1)(a). When a facility proposed for coastal siting is not a coastally dependent energy facility (see 980 CMR 9.01(2)), the alternative site to be proposed, evaluated and compared "shall be inland of the coastal zone." 980 CMR 9.02(1)(a).[33] Any alternative site "shall be reasonably determined and demonstrated to be capable of development and licensing or approval by all federal, state, regional and local agencies" (id.). The site evaluation and comparison must "include a justification of the necessity for or advantage of coastal siting along with an explicit definition of the process developed to compare alternative sites" (id.).[34]

In Section II.C below, the Siting Board reviews the Company's site selection process, including the consistency of the Company's proposal with the Coastal Zone facility regulations.

2. Environmental Impacts and Cost of the Proposed Facilities

As noted above, in implementing the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost,

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33/ The Company stated that the Edgar project does not meet the definition of a coastally dependent facility as set forth in 980 CMR 9.01(2) (Exh. BE-6, p. 5-1).

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

the Siting Council required project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable supply. In order to determine whether such a showing was made, the Siting Council required 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. 1991 Berkshire Decision, 23 DOMSC at 324; Enron, 23 DOMSC at 122; EEC, 22 DOMSC at 315; West Lynn, 22 DOMSC at 78; 1991 NEPCo Decision, 21 DOMSC at 377-379; MASSPOWER, 20 DOMSC at 382; 1990 Berkshire Decision, 20 DOMSC at 148.

In prior decisions, the Siting Council stated that an overall assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability.[35] Enron, 23 DOMSC at 137; EEC,

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35/ The Siting Board notes that project proponents are required to submit to the Siting Board a substantially accurate and complete description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of a generating facility provide a description of the primary and alternative sites and the surrounding areas in terms of: natural features, including, among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impact of the facility in terms of its effect on: the natural features described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 CMR 7.04(8)(e)2,6.

In cases where a site is proposed in the coastal zone, as defined by CZM statutes and regulations, the Siting Board's Coastal Zone Facility Site Selection, Evaluation and Assessment Regulations require: (1) an environmental description of each site and its vicinity, including a review of: significant land, air, and water use; ecology; geology; hydrology; meteorology; (2) an environmental analysis of construction impacts; (3) an environmental analysis of facility operation, including, but not limited to, land, air and water use impact, waste impacts, visual and aesthetic impacts; (4) a socioeconomic impact analysis, including measures to mitigate adverse impact during construction and operation; and (5) an analysis of all measures taken to comply with land, air, and water use and ecological standards, 22 DOMSC at 335-336. The Siting Council concluded that a facility proposal which achieves that appropriate balance is one that meets the Siting Council's statutory requirement to minimize environmental impacts. Enron, 23 DOMSC at 137; EEC, 22 DOMSC at 336.

The Siting Council also held that 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. EEC, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the Siting Council stated that 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. Id., at 334-335.

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

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policies, regulations, bylaws and statutes of the Commonwealth and its political subdivisions. 980 CMR 9.02(1)(b).

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

in order to make such a determination. 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.

Accordingly, in Sections II.D and II.E below, the Siting Board examines the environmental and cost impacts of the proposed facilities at the primary and alternative sites to determine: (1) whether environmental impacts would be minimized at each site; (2) whether an appropriate balance would be achieved at each site among conflicting environmental concerns as well as among environmental impacts, cost and reliability; and (3) which of the sites is superior on the basis of balancing environmental impact, cost, and reliability of supply.

B. Description of the Proposed Facilities at the Proposed and Alternative Sites

BECo proposes to construct a 306 MW combined cycle generating unit to be fueled by natural gas and No. 2 distillate fuel oil at one of two proposed sites (Exh. BE-6, p. 2-1, 5-1). The primary site is a 56-acre parcel of land located in Weymouth. (id., p. 2-1). The site, which is owned by BECo, is the location of the Company's now-retired Edgar Station generating units (id.). Active facilities on the site include two peaking combustion turbines, a barge off-loading dock, liquid fuel storage tanks and substation equipment (id.). Approximately 5.3 acres in the southwest portion of the site will be utilized for the proposed facility (Exh. BE-59, p. 6.5-3).

The Edgar site is bounded by the Weymouth Fore River on the north, south, and west sides (Exh. BE-6, p. 2-2). The east side of the site is partially bounded at its northern end by Kings Cove; at the center by Monatiquot Street and its adjacent residential area; and at the south end by Mill Cove (id.). The surrounding land area is predominantly densely populated (id.).

The major components of the proposed facility at the primary site include two combustion turbine generators with dual fuel capability; two HRSG with SCR;[36] a single steam turbine generator; a steam surface condenser; a demineralization system consisting of several storage tanks, including two 6,000 gallon tanks and a 200,000 gallon demineralized water storage tank; a circulating water intake structure; a circulating water discharge structure; main and unit auxiliary transformers; and three new 300-foot underground 115 kV lines from each of the three generating facility transformers to the existing 115 kV electrical switchyard (id., pp. 2-4, 2-5, 2-7 to 2-9).

The turbine generator building as proposed would be a rectangular structure that houses the steam turbine generator and the two combustion turbine generators (id., p. 2-6). An attached separate building will house the two HRSGs (id.). A general services building will house the water demineralization facility (id.).

Natural gas will be supplied to the facility by a new 10.7 mile, 24-inch pipeline to be constructed by Algonquin which will extend from the termination of an existing line in Avon, Massachusetts (HO-E-102, pp. 1, 2). Distillate fuel oil, if required for the operation of the facility, will be delivered to the site via barge, utilizing an existing wharf, off-loading equipment, and a 268,000 barrel capacity storage tank located at the northern portion of the site (Exh. BE-6, p. 2-8).

Off-site transmission of electric power from the existing switchyard will make use of the existing 115 kV Edgar to Medway overhead lines and will not require establishment of new off-site transmission or distribution facilities, nor require off-site reconductoring of existing lines (id.).

36/ BECo filed a new Best Available Control Technology ("BACT") plan with the MDEP on November 13, 1992 which contains a series of alternative fuel proposals that would have an effect on whether SCR will be utilized at the proposed facility (Exh. HO-RR-93). See Section II.D.1.a.(1)(a), below.

The Company stated that the proposed facility would cost approximately $210 million in 1994 dollars at the primary site (Exh. HO-RR-120, Table AS-5-2).

The alternative site proposed by BECo is a 300-acre parcel of land located in Uxbridge. (Exh. BE-6, pp. 5-10, 5-11). The alternative site consists of agricultural and undeveloped land and is located two miles southwest of the center of Uxbridge (id.). The site is bordered on the south by the Massachusetts/Rhode Island state line and by residential development along the north, east and west site boundaries (id.).

In addition to requiring the same major components that would be constructed at the Edgar site, the Ironstone site would require construction of additional facilities.[37] Due to the inland nature of the site, a closed loop heat rejection system will be required at the site, necessitating the construction of a mechanical draft cooling tower, a cooling tower make-up water pumphouse, and a water pipeline connecting the pumphouse to the cooling tower (id., pp. 5-21, 5-23, 5-24, 5-26). Additional construction both on and off-site includes a new 345 kV switchyard and transmission connections to BECO's existing 345 kV Sherman Road to Medway transmission line and a gas supply connection to Algonquin's interstate pipline system (id., pp. 5-21, 5-26; Tr. 56 at 143)[38].

The aforementioned Sherman Road to Medway transmission line passes within approximately 100 feet of the northwest

37/ The Siting Council notes that due to the possibility of BECo utilizing natural gas 365 days of the year, the alternative site may require a smaller oil tank than that presently existing at the Edgar site. See Section II.D.1.a.(1).

38/ The Company indicated that electrical connection of the proposed facility at the alternative site also would require transmission reinforcements on a segment of the regional transmission system outside the immediate area of the alternative site -- specifically, the addition of a new 17-mile 345 kV circuit extension between the Carpenter Hill/Millbury, MA substation and the Charlton, MA substation (Exhs. HO-RR-125, HO-RR-114).

extreme of the Ironstone site (id., p. 5-11). A natural gas pipeline owned by Algonquin passes within approximately 1400 feet of the site's northwest extreme (id.).

The Company stated that the proposed facility would cost approximately $246 million in 1994 dollars at the alternative site (Exh. HO-RR-120, Table AS-5-2).

C. Site Selection Process

1. Overview of Siting Process

BECo asserted that the process which led to the selection of the primary and alternative sites for the Edgar project included a series of siting studies conducted over the period 1978 to 1989 (BECo Initial Brief, pp. 184-185). The Company stated that the process began with a site selection study performed in 1978 by Stone & Webster Engineering Corporation ("Stone & Webster") to identify and evaluate sites to construct coal- or nuclear-fueled generating stations ranging in size from 800 to 1500 MW ("1978 Study") (Exh. UX-37, p. E-1).

BECo stated that Stone & Webster performed two follow-up studies for BECo in 1984 ("1984 Study") and in 1985 ("1985 Study") (Exhs. UX-3, p. 1-1, UX-46, p. 1). The Company indicated that the 1984 Study evaluated sites in eastern Massachusetts for the construction of 400 MW coal-fired units utilizing information and data obtained from the 1978 Study (Exh. UX-3, p. 1-1).[39]

BECo indicated that the 1985 Study evaluated possible sites for the construction of a 440 MW combined-cycle gas turbine

39/ BECo stated that the potential site inventory of 61 sites in the 1984 Study included all of the potential sites identified in the 1978 Study in eastern Massachusetts and, in addition, all BECo-owned sites capable of supporting at least one 400 MW fossil unit and several new sites in the Taunton and Blackstone River Valleys (Exh. UX-3, pp. 3-1, 3-3, 4-2). From the potential site inventory of 61 sites, the 1984 Study ultimately selected four preferred sites: the Edgar and Ironstone sites, the Mystic site in Everett, Massachusetts, and the Nickel Mine Hill site in Dracut, Massachusetts (id., pp. 5-54, 6-1, 6-6).Z generating station (Exh. UX-46, p. 1). The Company stated that the 1985 study evaluated only the four preferred sites identified in the 1984 Study and one additional BECO-owned site (id., p. 1, Addendum, pp. 1 ff.).[40] The 1985 study concluded that the Mystic site and the Edgar site were the preferred sites, and ranked the Edgar site first with respect to costs. (id., Addendum, p. 7).[41]

BECo stated that in 1987 the Company evaluated the Ironstone and Nickel Mine Hill sites for the purpose of identifying an inland site as a potential inland alternative to the Edgar site (Exh. BE-6, p. 5-10). The Company stated that this evaluation, which was based on land availability, rail access potential, and transmission access, led to the selection of the Ironstone site as the preferred inland alternative site for the proposed facility (id.). The Company also stated that the 1987 evaluation confirmed that the Edgar site should be the primary site for development of a generating facility (Tr. 29, p. 126).[42]

Finally, the Company stated that a "Site Update Survey" was completed in 1989 (Exh. BE-55, p. 4). BECo stated that the 1989 study, which was prepared for the Company by United Engineers and Constructors, Inc. ("UE&C"), was based on information and data obtained during site surveys conducted in

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40/ The additional site reviewed in the 1985 Study was the BECo-owned K Street site in South Boston (Exh. UX-46, Addendum). The Company stated that all five sites were also evaluated for their ability to support an additional coal plant and coal gasification facility (id., p. 1).

41/ The Company also indicated that the Edgar site had the most favorable environmental score in the 1984 Study (Exh. UX-3, Table 6-5).

42/ The Siting Board notes that Exhibit UX-47, described by BECo as the 1987 Availability Review, does not compare the Ironstone and Nickel Mine Hill sites, as it does not include any reference to Nickel Mine Hill. Nor is there any reference to the Edgar site in this document.

1989, and on the previous siting studies conducted for the Company (Exh. UX-48, p. 2). The Company stated that the review conducted by UE&C supported the results of the prior siting studies, confirming the Edgar site as the primary site and the Ironstone site as the alternative site (id., p. 13).

In its review of BECo's site selection process, the Siting Board will focus primarily on the 1984 Study, which examined sites in eastern Massachusetts and developed and applied environmental and cost criteria for use in evaluating those sites, and on the 1985 Study, which evaluated the preferred sites from the 1984 Study for a combined-cycle gas facility.[43]

2. Description

a. Development of Siting Criteria

BECo asserted that the criteria developed and the methodology utilized in the 1978 Study and the 1984 Study were essentially identical, but that the 1984 Study expanded on the environmental criteria used to evaluate potential sites (BECo Initial Brief, at 189). The 1984 Study identified a "region of interest" -- namely, eastern Massachusetts -- for which siting criteria were developed and from which potential sites were selected (Exh. UX-3, p. 1-1). The 1984 Study employed three phases in developing siting criteria: (1) identification of candidate areas ("Phase 1"), (2) identification of potential sites ("Phase 2"), and (3) selection of preferred sites ("Phase 3") (id., p. 2-4).

In Phase 1 of the 1984 Study, exclusion criteria were developed for removing large areas from consideration in the defined region of interest (id., pp. 3-1, 3-2). The two exclusion criteria used to develop candidate areas were: (1)

43/ Because the 1978 Study focussed on 800-1500 MW coal and nuclear facilities, and because the 1987 and 1989 siting reviews were not comprehensive site selection studies, the Siting Board does not place significant weight on these documents in its review and analysis.

incompatible land use (e.g., military installations, airports, national and state parks and forests, and wildlife refuges) and (2) water availability (id., p. 3-2).

In Phase 2 of the 1984 Study, potential sites were identified and evaluated within the candidate areas defined in Phase 1 using a series of environmental and design criteria (id., p. 4-1). Phase 2 consisted of four steps: (1) screening areas with major engineering or environmental constraints ("Step 1" or "area deferral") (id., p. 4-1, Table 4-1); (2) comparing areas based on engineering suitability and environmental constraint criteria ("Step 2" or "area comparison") (id., p. 4-1, Table 4-2); (3) identifying sites within areas based on site area requirements, such as site size ("Step 3" or "site identification") (id., p. 4-2, Exh. UX-37, pp. 5-1, 5-6 to 5-8); and (4) evaluating sites based on engineering suitability and environmental constraint criteria ("Step 4" or "site evaluation") (Exh. UX-3, p. 4-2).

As part of Step 1, the Company identified the following deferral criteria which were developed to screen areas for fossil plants: topography, proximity to water, hydrology, water quality, land use, socioeconomics, and ecology (id., Table 4-1). The Company stated that the following engineering suitability and environmental constraint criteria were developed for use in Step 2: topography, proximity to water, land use, and air quality (id., p. 4-1, Table 4-2). The Company did not list criteria for identifying specific sites in the selected areas as part of Step 3.

For purposes of site evaluation in Step 4 of Phase 2, the following engineering suitability criteria were developed: topography, foundations, water availability, proximity to water and railway transportation, proximity to transmission, and proximity to load center (id., pp. 4-2 to 4-11).[44] In addition, the following environmental constraint criteria were developed for fossil fuel plants in the 1984 Study: land use, aquatic ecology, terrestrial ecology, air quality/meteorology, and aesthetics (visibility) (id.).[45] The Company stated that these criteria were scored according to a zero to five scale for the engineering suitability criteria and a zero to minus five scale for the environmental constraint criteria (id., p. 4-2). The Company stated that the scoring consisted of a gross score with no weighting (Tr. 27, pp. 184-185). By the end of Phase 2, the Company had identified eight potential sites (Exh. UX-3, pp. 4-20, 4-21).

BECo stated that Phase 3 was performed to identify preferred sites from among the eight potential sites identified in Phase 2 (id., p. 5-1). Phase 3 consisted of three steps, including: (1) a cost evaluation, (2) an environmental impact evaluation, and (3) an evaluation based on permitting issues (id.).

The cost evaluation was based on estimates of differential 1984 capital and operating costs for each candidate site (id.). Plant costs not influenced by site location were not included in the estimate (id.). The criteria for the cost evaluation included site development, foundations, cooling system, materials

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44/ In the 1978 Study, both hydrology and land requirements were considered as engineering and suitability criteria (Exh. UX-37, p. 5-2). These criteria were both deleted in the 1984 Study without explanation, while proximity to water and railway transportation for fuel delivery was added as a criterion in the 1984 Study (Exh. UX-3, pp. 4-2 to 4-19).

45/ The 1978 Study also considered the following environmental constraint criteria: water use, socioeconomics, and water quality (Exh. UX-37, p. 5-2).

handling, transportation, labor, and transmission (id., Fig. 5-1).[46]

The environmental impact evaluation consisted of a rating and weighting analysis utilizing criteria designed to reflect the environmental acceptability of each site option (id., pp. 5-3, 5-4).[47] The Company stated that the criteria developed for the environmental assessment evaluation were as follows: terrestrial ecology, aquatic ecology, water quality, socioeconomics,[48] noise, hydrology, hydrothermal, land use, and aesthetics (id., Table 5-1, pp. 5-14 to 5-36).[49] Subcriteria were developed for many of these criteria,[50] and weights were established for each of the environmental criteria to reflect the fact that some

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46/ Site-related costs were estimated for each of these criteria (Exh. UX-3, pp. 5-2, 5-3); however, land acquisition costs were not considered (id., p. 5-8).

47/ BECo stated that the Nominal Group Technique ("NGT") was used to define the criteria for Phase 3 (Exh. UX-37, p. 6.1-3). According to the Company, the NGT procedure was designed to ensure a systematic group decision making process (id.). For all environmental criteria, NGT panels of Stone and Webster individual discipline specialists followed a documented NGT procedure to identify pertinent issues within each discipline, and a rating scale and weighting factor for each criterion (id.).

48/ The Company defined socioeconomics as the economic benefit which a community or town could derive from hosting a facility (Exh. UX-3, pp. 5-23 to 5-26). The Company included within its socioeconomic criterion the following subcriteria: per capita income, unemployment rate, effective tax rate, and existing municipal costs (id.).

49/ The Company stated that environmental impacts of areas remote from the sites of the proposed facilities were not performed (Exh. UX-37, p. 6.4-1). Therefore, concerns such as impacts from transmission lines and pipeline routes were not evaluated (id.).

50/ As an example, the criterion of aquatic ecology included the following subcriteria: rare and endangered species, value of habitat, and sport and commercial fisheries (Exh. UX-3, pp. 5-19 to 5-21).

criteria may have a more significant impact on the licensing process than others (id.; Exh. UX-37, p. 6.1-6).[51]

BECo explained that in the last step of Phase 3, permitting issues were identified for each site option in order to highlight potential siting problems that had been identified in the environmental evaluation but that could not be quantified in the environmental score (Exh. UX-3, p. 5-5). The Company stated that permitting issues considered in this step of the process were the following: air quality,[52] solid waste disposal,[53] land availability,[54] and public acceptance (id., p. 5-37).

BECo explained that in the 1985 Study, Stone and Webster evaluated the site-related differential capital and operating costs for each of the four preferred sites identified in the 1984

51/ The subcriteria were scored and weighted within each criterion, thus producing a rating factor for each criterion (Exh. UX-3, pp. 5-3, 5-4, 5-14 to 5-36). Weights were then assigned to each criterion on a scale of 1 to 10 (id., pp. 5-3, 5-4, Tables 5-1 and 6-4; Exh. UX-37, p. 6.1-7). The weights and the rating factors for each criterion were then multiplied to provide a score for each criterion (Exhs. UX-3, Table 5-2, UX-37, p. 6.1-7). The scores were then added up to provide a final environmental score for each site option (id.). According to the Company, the weights were developed by a panel of individuals encompassing a broad range of expertise using the NGT (see n. 47, above) (Exh. UX-37, p. 6.1-6).

52/ According to the Company, the air quality/meteorology criterion was not rated or weighted because site specific dispersion modeling was beyond the scope of the site selection studies (Exh. UX-3, p. 5-38).

53/ Solid waste disposal was a major issue in the 1984 Study because coal-fired power plants produce large quantities of solid wastes (Exh. UX-3, p. 5-43). Therefore, in the 1984 Study, the potential for on site disposal, necessitating a larger site size, was considered to be preferable (id.).

54/ The 1984 Study assumed that sites that were already developed with sufficient additional available land for expansion were preferable to undeveloped sites (Exh. UX-3, p. 5-44).

Study (Exh. UX-46, p. 1-1).[55] The Company stated that costs evaluated for each site included: (1) capital costs for site development/site preparation, foundations, fuel delivery and storage, heat rejection systems, power transmission, labor productivity, and (2) operating costs for selected items such as decremental generation, auxiliary power, and incremental capability (id., pp. 3-1, 3-2, 3-4 to 3-10). Acquisition costs for land and easements for pipeline and transmission lines and other necessary easements were not evaluated (id., p. 3-4, Addendum, p. 4).

The 1985 Study also included a review of the federal and state permits and approvals required for the construction and operation of a combined-cycle facility (id., pp. 4-1 to 4-15). However, the 1985 Study identified no criteria to evaluate the sites with respect to permitting issues (id.). The 1985 Study noted that one of the major differences between a combined cycle plant and a coal plant is that the combined-cycle facility does not require disposal of solid waste (id., p. 4-1).[56]

b. Application of Siting Criteria

The Company stated that it originally considered a geographical area consisting of Massachusetts, Rhode Island, and southeastern New Hampshire in the 1978 Study, and identified 20 candidate areas (Exh. UX-37, p. 1-1). In the 1984 Study, BECo indicated that the region of interest was to consist of only

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55/ In accordance with BECo's specifications, in addition to a cost evaluation other purposes of the 1985 Study included: (1) an evaluation of the facility layout; (2) preparation of an engineering and construction schedule for the facility; (3) an evaluation of each site for possible future coal-fired units and coal-gasification facilities; (4) identification of all federal and state environmental permits and approvals; (5) preparation of detailed environmental permitting schedules; and (6) evaluation of risks associated with sequential and parallel permitting and construction activities (Exh. UX-46, pp. 1-1, 1-2).

56/ Solid waste disposal was one of the licensing issues evaluated in the 1984 Study (Exh. UX-3, p. 5-37).

eastern Massachusetts, as it had determined from the 1978 Study that an adequate inventory of viable candidate sites could be identified in this area without considering other areas (Exh. UX-3, p. 3-1; Tr. 27, p. 128). The Company stated that eastern Massachusetts was selected due to the distinct advantage of locating plants closer to BECo's own load center and service territory (Tr. 32, p. 143).

In the 1984 Study, BECo applied the two Phase 1 exclusion criteria to identify candidate areas in the region of interest, and selected eight areas (Exh. UX-3, pp. 3-1 to 3-3).[57] As part of Phase 2 of the 1984 Study, the Company utilized deferral criteria, engineering suitability criteria, and environmental constraints to identify 61 potential sites in candidate areas (id., pp. 4-1, 5-3). BECo indicated that, based on the 12 criteria related to engineering suitability and environmental constraints, it developed overall scores for the 61 sites (id., pp. 4-2 through 4-18; Exh. BE-48, p. 6).

BECo stated that the highest scoring sites were visually inspected by helicopter and, therefore, some sites with initial high scores were rejected based on such inspection (Exh. UX-3, p. 4-20). The Company stated that in order to be selected, a site must have a total score of 15 or more, and that each candidate area could provide only one site meeting this scoring threshold; as a result five sites were identified (id.). In addition to those sites identified, the three BECo-owned sites were included, for a total of eight candidate sites consisting of: the Edgar, Mystic, Ironstone, and Nickel Mine Hill sites, and the Otis site in Bourne, the Cowdry Hill site in Groton, the Lynn Harbor site in Lynn and the Pilgrim site in Plymouth (id.,

57/ The candidate areas selected were Metro Boston, North Shore, Plymouth, Merrimack West, Blackstone, Taunton, Buzzards Bay, and the Lower Cape (Exh. UX-3, p. 3-3).

pp. 4-20 and 4-21).[58] The Company then indicated that the eight sites were reviewed by BECo's Real Estate Department, whereupon the Lynn Harbor site was deemed to be unavailable; therefore, seven sites advanced to Phase 3 (id.).

The Company indicated that, to evaluate the preferred sites in Phase 3, it separately ranked the sites with respect to cost and non-cost items (id., p. 5-5; Tr. 27, p. 97). BECo stated that it utilized site layouts as the basis for the site related cost differentials and the environmental assessment (Exh. UX-3, p. 5-1).

With respect to the non-cost items, the Company developed discrete ratings for each site generating a score for each criterion and multiplying that score by the identified weighting factor, and summing each score for a final tally (id., p. 5-4). The Company indicated that the Edgar site had the highest (best) environmental score, with the Mystic site ranked second (id., p. 6-2). As noted above in Section II.C.2.a., the Company stated that it also considered environmental permitting issues that could not be included in the rating and weighting system (id., p. 5-3).

For cost items, the Company indicated that it used estimates of differential 1984 costs for six capital and four operating cost items, representing plant costs influenced by the site location (id., pp. 5-1 to 5-3). The Company stated that as a result of the Phase 3 differential cost and environmental scoring of the seven sites, the following four sites were deemed preferable: the Edgar, Mystic, Nickel Mine Hill and Ironstone sites (Exh. BE-48, p. AS 1-7).

BECo stated that the candidate site inventory for the 1985 Study initially consisted of the four Phase 3 preferred sites from the 1984 Study (id., p. AS 1-8). BECo stated that a fifth

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58/ The scores for each potential site are Mystic, 24; Edgar, 23; Ironstone, 21; Pilgrim, 20; Lynn Harbor, 20; Nickel Mine Hill, 18; Cowdry Hill, 17; and Otis, 17 (Exhs. BE-48, p. 6, UX-3, Table 4-4).

site -- the BECo owned K Street site -- was added in an addendum (id.).[59] The Company stated that the evaluation of the five sites for combined-cycle generation was based on (1) the Phase 3 cost differential criteria from the 1984 Study,[60,61] and (2) the environmental site scores from the 1984 Study (id., p. AS 1-9; Tr. 29, p. 97). The Company stated that it did not consider whether any of the individual environmental scores from the 1984 Study would be different given the change in the 1985 Study from coal technology to combined-cycle technology (Tr. 33, p. 50). The Company stated that the criteria used were not very specific to the technologies, and that an existing site condition would not change between technologies (Tr. 33, p. 50). In addition, the Company stated that it did not perform any further environmental analysis after the 1984 Study, as it felt that none of the situations had changed at any of the sites to warrant a new comparison (Tr. 29, p. 163).

Based on the 1985 Study, the Edgar site exhibited the lowest site specific total capital and operating cost, with the K Street site and the Mystic site ranked as second and third (Exh. UX-46, Addendum, p. 7). The Company noted that high operating cost differentials associated with the two inland sites

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59/ Mr. Schmidt stated that the K Street site was not included in the earlier rounds because the site is somewhat small, approximately seven acres, and BECo previously had other plans for the site (Tr. 33, p. 44). The Siting Board notes since K Street was not added until the 1985 Study, it was not subjected to an environmental assessment which would have resulted in an environmental score.

60/ The Siting Board notes that the 1985 Study and the earlier 1984 Phase 3 cost criteria vary somewhat, in that the 1985 Study added fuel delivery and storage and did not include material handling, transportation, and transshipment of wastes (Exhs. UX-46, pp. 3-1, 3-2, UX-3, pp. 5-2, 5-3).

61/ The Company stated that the cost estimates for the 1985 Study were based on an oil-fired combined cycle unit utilizing No.2 fuel oil; and there was no cost consideration of natural gas-fired units (Tr. 29. pp. 109, 110; Exh. UX-46, p. 3-3).

reflected the use of cooling towers at those sites, while once-through cooling could be used at the Edgar, Mystic and K Street sites (id., pp. 3-7, 3-11, Addendum, pp. 5, 7). The 1985 Study concluded, however, that there would not be a significant difference in total site differential costs among the five sites (id., pp. 5, 7).[62] The 1985 Study also concluded, as did the 1984 Study, that adding a new unit to an existing site is expected to be easier, with respect to environmental permitting, than building at a new site, and that the Mystic and Edgar sites are preferred because they are existing sites owned by BECo (id., Addendum, p. 7).[63]

Mr. Schmidt stated that as of 1987, BECo had decided that the Edgar site was to be the primary site based on the siting studies reviewed up to that point, but had not specifically identified an alternative site for purposes of Siting Board review (Tr. 29, p. 126). The Company stated that, although the Mystic site was the second best site in eastern Massachusetts, according to CZM requirements, an alternative inland site must be considered, and therefore BECo focused on determining whether it would select the Ironstone site or the Nickel Mine Hill site as

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62/ The 1985 Study indicates that the maximum difference in total site related costs between the lowest cost, estimated for the Edgar site, and the highest cost, estimated for the Nickel Mine Hill site, represents less than 10 percent of the installed capital cost, and is within the accuracy of an order-of-magnitude estimate (Exh. UX-46, Addendum, p. 7).

63/ The Siting Board notes that the conclusions made in the 1985 Study were based on the original four sites without including the K Street site. Further, while the 1985 Study selected both the Edgar and Mystic sites, this Study stated that development of either site for multiple facilities is limited by the availability of land and, therefore, it may be wise to develop one site for a combined-cycle facility and one for a coal facility (Exh. UX-46, p. 5). The Company stated it designated the Edgar site for a combined-cycle facility since it was difficult to assess the community reaction to a new coal unit at that site, and designated the Mystic site for coal (id., pp. 5, 6).

the alternative site (Tr. 27, p. 145; Exh. BE-6, p. 5-1).[64] The Company stated that it concluded from the 1987 Study that a majority of the Nickel Mine Hill property could not be obtained by Boston Edison based on current ownership and current use of the property, and therefore, the Ironstone site was selected as the most viable inland alternative (Exh. UX-48, p. 10).

3. Arguments of the Parties

The Company argues that its site selection process was thorough, exhaustive, and complete, and "far superior to any other siting process" previously presented to the Siting Council (BECo Initial Brief, p. 194). BECo emphasizes the "wealth of detail" and the thoroughness of its site selection process in support of its argument that its process complies with Siting Board standards (id., pp. 194-195).

Uxbridge argues that BECo's site selection process was fundamentally flawed in a number of important respects (Uxbridge Initial Brief, p. 8). Uxbridge argues that BECo's siting studies were not performed for combined cycle technology, but for large nuclear or coal-fired facilities (id., pp. 13-16). As a result, Uxbridge argues that potential sites for combined cycle technology were either excluded from the siting analysis, or not actively advanced by BECo (id., p. 9). Uxbridge also argues that the studies relied upon by BECo are substantially outdated (id., pp. 16-19).

Uxbridge further argues that BECo's ranking of environmental factors is flawed because of the inclusion of the criterion "socioeconomics" as one of the environmental criteria

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64/ According to 980 CMR 9.02(1)(a), if the proposed site is located in a coastal zone, and it is deemed not to be coastally dependent, an alternative site must be located inland of the coastal zone (Exh. UX-6, p. 5-1). The Company stated that the Edgar site is located in the coastal zone and that the site is not coastally dependent according to the CZM Program, Policy 8 and 980 CMR 9.01(2) (Exh. BE-6, p. 5-1).

(id., p. 19).[65] Uxbridge argues that the inclusion of this criterion in the environmental ranking "is highly misleading and skews the environmental analysis" (id., p. 20). Uxbridge also argues that the use of the socioeconomics criterion as defined by the Company promotes the selection of lower-income communities as facility hosts (id., p. 22).

Uxbridge asserts that the siting studies performed in the site selection process were not designed to, nor did they, identify the best alternative sites for the proposed facility (id., p. 1).[66] Finally, Uxbridge argues that the Siting Board should expressly disapprove BECo's site selection process, and find that selecting its best site and a clearly inferior site as the sole noticed alternative does not constitute compliance with the statutory and decisional law on alternative site analysis (id., p. 2).

In response to Uxbridge, the Company stated that its site selection process identified a very large universe of possible sites, and therefore "[i]t is hard to accept" that the Company missed a potential site because the 1978 and 1984 Studies were not performed for a combined-cycle facility (BECo Initial Brief, pp. 210-211).

65/ Uxbridge notes that BECo gave significant weight to the socioeconomics criterion, ranking it as more important than, inter alia, the hydrology, hydrothermal, and noise criteria, and almost as important as water quality (Uxbridge Initial Brief, p. 19).

66/ Uxbridge argues that the Ironstone site was inferior to the Edgar site and several other sites, notably the Mystic and K Street sites (Uxbridge Initial Brief, p. 25). Uxbridge notes that the 1984 Study indicates that at least four of the seven sites analyzed were superior to the Ironstone site for environmental impacts (id.). Uxbridge asserts that BECo has admitted that the CZM regulations did not preclude it from noticing the best alternatives (id., p. 26).

4. Analysis

a. Development of Siting Criteria

This case presents the first utility-proposed generating facility in recent years, and only the second generating facility in recent years that did not involve cogeneration with steam sales to a host industrial plant. The Siting Board notes that a utility has a greater opportunity to engage in an ongoing site selection process and to examine a greater range of sites than a developer of an individual cogeneration project. Nevertheless, the standard of review established in previous decisions and described above in Section II.A.1., remains applicable to utility-proposed generating facilities.

The Siting Board notes that in past decisions, the Siting Council discouraged the development of overly broad site selection criteria. 1992 Berkshire Decision, 25 DOMSC at 61-62; EEC, 22 DOMSC at 320, 1990 Berkshire Decision (Phase II), 20 DOMSC at 162. Prior decisions also expressed concerns regarding the absence of weights for site selection criteria. 1992 Berkshire Decision, 25 DOMSC at 62; Enron, 23 DOMSC at 127; EEC, 22 DOMSC at 321; West Lynn, 22 DOMSC at 78-79; MASSPOWER, 20 DOMSC at 378-379; 1990 Berkshire Decision (Phase II), 20 DOMSC at 161-162. Furthermore, previous Siting Council decisions stated that the development of numerical values and weights and the ranking of alternatives based on such numerical values and weights are necessary steps in any process for identifying and evaluating routes or sites. 1992 Berkshire Decision, 25 DOMSC at 62, 1991 Berkshire Decision, 23 DOMSC at 329.

In this case, the Company's approach to developing site selection criteria was detailed and iterative, and included quantitative rating and weighting approaches. The Company developed specific environmental criteria and cost criteria in its site selection process, and divided the environmental criteria into subcriteria, which were largely based on quantifiable parameters. Thus, the Company has addressed concerns raised in previous reviews regarding the development of overly broad criteria as part of a Company's site selection process. The Company has also incorporated numeric scores and weights in its site identification and evaluation process. Therefore, the Company has addressed concerns that weights and numerical values be developed as part of a company's siting criteria.

The Siting Board notes that, generally, the siting criteria developed by the Company were appropriate. For example, land use, water availability, water quality, air quality, terrestrial ecology, aquatic ecology, aesthetics, noise, hydrology, and hydrothermal impacts were all appropriate environmental criteria developed by BECo for a project of this type and are similar to criteria approved by the Siting Council in previous decisions. Furthermore, the costs of site development, foundations, cooling systems, fuel delivery and storage, materials handling, transportation, labor, and transmission are all appropriate cost criteria developed by the Company.

However, the Siting Board shares a number of the concerns raised by Uxbridge concerning the development of the Company's site selection criteria. First, as Uxbridge pointed out, the 1984 Study, in which the Company developed its environmental criteria, weights, and scoring procedures, was performed for coal facilities and not for oil or gas-fired combined cycle facilities.[67] Clearly, certain criteria developed for coal facilities may not be applicable to the siting of a gas or oil-fired facility. For example, solid waste disposal was considered to be an important licensing issue in the 1984 Study because coal plants produce large amounts of solid waste, but

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67/ The environmental criteria developed in the 1984 Study were never revisited, revised, or even applied in the 1985 Study, even though that study was performed for a combined-cycle facility. Furthermore, no environmental criteria were developed in the 1985 Study. In fact, no comparative analysis was performed in the 1985 Study on environmental issues.

this issue is not relevant to the siting of a gas or oil facility. Second, the Siting Board notes that the record is unclear as to how the Company evaluated site size in the site selection process as the technology proposed in each study was modified. The Siting Board notes that a combined-cycle facility fueled by gas or oil requires much less land area than a coal facility, which requires additional storage for both fuel and solid waste. BECo recognized that a combined-cycle facility does not require additional area for disposal of solid waste in its 1985 Study, but despite this acknowledgement, the Company did not revisit the list of 61 potential sites evaluated in the 1984 Study to determine if any potentially preferable sites had been eliminated.

Conversely, criteria which would be specifically appropriate to the siting of a gas-fired plant were never considered or evaluated. Indeed, proximity to a gas pipeline to fuel the facility was not a siting criterion in any of the studies, and the environmental and cost impacts of such a pipeline were not considered. Thus, as Uxbridge pointed out, potential sites well-suited for a gas-fired combined cycle facility could have been screened out of the process or not considered at all because some of the criteria that were developed were inappropriate.

In regard to the Company's specific criteria, the Siting Board notes a valid argument raised by Uxbridge regarding the criterion of socioeconomics. The Siting Board is concerned that the Company has defined socioeconomics in such a way as to favor selection of sites in lower income communities.[68] In

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68/ For example, the Cowdry Hill site was eliminated from further consideration primarily due to the ratings it received for each of the four socioeconomic criteria (Exh. UX-3, p. 5-91). Based on these ratings, the Company assumed that there would be significant public opposition to the project at that site even though the Company had no specific information to evaluate public attitudes toward developing the site for power generation (id., p. 5-91).

particular, the Siting Board notes that the subcriteria of per capita income and unemployment rate are not necessarily indicative of a good siting location or of community sentiment towards a project proposal.[69,70] A more appropriate way to measure community reaction to a project proposal is to incorporate community input into the site selection process and include community concern as one of the siting criteria. In the past, project proponents have been encouraged to incorporate community input into their site selection process. 1992 Berkshire Decision, 25 DOMSC at 61; 1990 Berkshire Decision (Phase II), 20 DOMSC 109 at 163.[71]

The Siting Board also has some concerns with the Company's assignment of weights to the criteria. First, the Company did not explain its rationale for assigning specific numerical weights to the environmental criteria and subcriteria.[72] Second, the Company failed to develop weights for the permitting criteria considered in Phase 3 of its analysis. Air quality, in

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69/ The other subcriteria in this criterion, tax rate and existing municipal costs, are also not necessarily reflective of the suitability of a particular site for a power facility or of community acceptance of a project.

70/ The Siting Board also notes its concern that the Company assigned a weight to the socioeconomics criterion greater than or comparable to individual environmental criteria such as hydrothermal, noise, hydrology and water quality.

71/ Concerning other specific criteria, the Siting Board notes that the Company provided no explanation as to why hydrology, which was an engineering suitability criterion in the 1978 Study, was dropped from consideration in the 1984 Study. It is also unclear to the Siting Board as to why the Company deleted water use and water quality from consideration in the preferred site evaluation (Phase 2, Step 4) of the 1984 Study, since these criteria were both included in this step in the 1978 Study. The criterion of water use does not appear to have been developed for any of the steps in the 1984 Study.

72/ The Company did explain the method that was used to develop the criteria, namely NGT, but no rationale was provided as to how particular numerical weights were assigned to specific criteria.

particular, is a significant environmental criterion that was not weighted or scored.

In response to the concern of Uxbridge relative to the age of the studies, the Siting Board notes that the most recent study in which environmental criteria were developed was the 1984 Study, while the most recent study in which cost criteria were developed was the 1985 Study. The Siting Board recognizes that the Company filed its original petition in this case in 1990 and that the Company began design work on the proposed project sometime earlier. Thus, the studies which led to the selection of the Edgar and Ironstone sites were only a few years old at the time the project was developed. Furthermore, the Company noted that it reviewed these site selection studies in 1987 and again in 1989. The Siting Board expects companies to review the continued appropriateness of site selection criteria, weighting, scoring and ranking developed in studies that are prepared several years prior to the filing of a company's petition.

In sum, despite the concerns described above, including the concern that some criteria were inappropriate for a gas-fired combined-cycle facility, BECo has developed generally appropriate cost and environmental criteria, and developed numerical values and weights for its site selection process. Accordingly, the Siting Board finds that BECo has developed a minimally reasonable set of criteria for identifying and evaluating alternative sites.

b. Application of Siting Criteria

In regard to the identification of specific sites at which to locate the proposed facility, BECo undertook a comprehensive search for available sites in the 1984 Study. The application of Phase 1 exclusion criteria and the environmental and deferral criteria in the first steps of Phase 2 in the 1984 Study yielded a pool of 61 sites, a significant number of sites. In addition, the initial methodology in applying the above criteria to the 61 sites was generally appropriate -- utilizing scores for both the engineering and environmental criteria. The Company's development of weighted scores in Phase 3 of the 1984 Study was generally sound.

The Siting Board notes that the 1989 Study was a synopsis and affirmation of the previous studies. This check is important in that the Company did successively build upon iterative studies and was involved in ongoing site selection activities prior to final development plans. However, the Siting Board notes that it may be appropriate to update the scoring of sites, or review applicable criteria, in cases where a significant amount of time has lapsed since the last comprehensive site selection study was conducted.

The Siting Board has some concerns with the Company's application of siting criteria. First, the selection of the final sites that were to be carried on to the Phase 3 analysis was arbitrary. The designation of a score of 15 or more as the cut-off point was not explained, nor was the rationale for selecting only one site with said score in each candidate area justified by the Company.[73]

Second, the two-tiered weighting system applied to the Phase 3 criteria was cumbersome. In the past, we have determined that the assigning of numerical values and weights which place an excessive emphasis on numerical differentiation, given the highly judgmental nature of the scoring system, may yield a rank based on relatively insignificant substantive differences. 1991 Berkshire Decision, 23 DOMSC at 329. Further, as noted in Section II.C.2.a., above, there was no explanation of how the importance factors or weights were developed.

Thus, the Company utilized a parallel ranking system, generating a specific environmental score and a specific cost

73/ The Siting Board acknowledges the importance of geographic diversity; however, the inclusion of more than one site in a candidate area does not preclude the adherence to the goals of geographic diversity. In addition, the record does not demonstrate that BECo specified geographic diversity as an objective in this instance.

differential value for each site. However, the Company did not explain how it integrated the separate environmental and cost scores in Phase 3 in order to select its preferred site. Further, we note that the use of specific cost differentials may be misleading, as the relationship of the differential cost to the overall cost of each item is not provided. Finally, the use of costs from earlier iterations of the Company's analysis is problematic, as the costs are outdated and are based on a 400 MW coal plant rather than a 300 MW gas-fired combined cycle facility such as the Company is proposing to construct.

The Siting Board has noted a number of flaws in the application of the Company's site selection criteria. However, the Siting Board also notes that BECo identified a significant pool of possible sites, and consistently applied its criteria to these sites. In addition, scores and rankings were generally appropriate, and the Company conducted a review of its siting studies prior to filing its petition in this case.[74]

Accordingly, the Siting Board finds that BECo has appropriately applied its criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior sites.[75]

74/ In regard to the concerns raised by Uxbridge that the application of criteria related to a coal-fired facility may have led to the elimination of a superior site, there is no evidence in the record indicating that this occurred.

75/ In regard to Uxbridge's argument that the Company failed to notice its best alternatives to the Edgar site, the Siting Board agrees with BECo that since CZM regulations require it to notice an alternative inland site, that the Ironstone site or some other inland site would have to be a noticed alternative even if the Company had noticed the Mystic or K Street sites. Further, as BECo states, neither the Siting Board's nor CZM's regulations require the Company to notice three sites, as Uxbridge contends the Company should have done. However, as the Siting Council stated in the 1990 Berkshire Decision (Phase II), inclusion of the "best alternatives" as noticed alternatives in the applicant's filing may allow the Siting Board to proceed more expeditiously, in the event such a best alternative is found to be clearly superior to the applicant's proposal (20 DOMSC at

5. Geographic Diversity

In this section, the Siting Board considers the second prong of the practicality test -- whether BECo's site selection process included consideration of site alternatives with some measure of geographic diversity. In addition, the Siting Board reviews the consistency of the Company's siting plans with Coastal Zone facility regulations.

BECo asserts that its siting process was comprehensive in that a broad geographical area was considered and a large number of potential sites with geographic diversity were identified (BECo Initial Brief, p. 186). The Company also asserts that since the Edgar and Ironstone sites are located approximately 40 miles from each other in substantially different environmental and socioeconomic settings, they are clearly geographically diverse (id., p. 211). BECo noted that its primary site is located in the coastal zone as defined pursuant to the CZM Act, 16 U.S.C. § 1453 (Exh. BE-6, p. 5-1). The Company stated further that the Edgar project does not meet the definition of a coastally-dependent facility as set forth in 980 C.M.R. 9.01(2) (id.).

We require that an applicant must provide at least one noticed alternative with some measure of geographic diversity.[76] 1991 Berkshire Decision, 23 DOMSC at 332; Enron, 23 DOMSC at 130; 1991 NEPCo Decision, 21 DOMSC at 390-394; 1990 Berkshire Decision, 20 DOMSC. The Siting Council previously

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155-156). The 1990 Berkshire (Phase II) decision states that such a circumstance may arise because additional information comes to light, or events take place, which adversely affect the ability of the applicant's proposal to meet the identified need with a minimum impact on the environment at the least cost (id.).

76/ In MASSPOWER, the Siting Council set forth a standard that, if met, would exempt certain cogeneration facilities from the noticed alternative requirement (20 DOMSC at 382). However, Edgar is not a cogeneration facility, therefore it is not exempt.

determined that simple quantitative diversity thresholds are not appropriate for evaluating geographic diversity, and that the specific characteristics of each site must be scrutinized as well as the locational separation. Enron, 23 DOMSC at 131; 1991 NEPCo Decision, 21 DOMSC at 392.

Here, BECo has provided two sites located 40 miles apart, where one site is located in an urban area and one site is located in a rural area. Further, one site is located in a coastal region and one is located inland. Accordingly, based on the foregoing, the Siting Board finds that BECo has identified at least two practical sites with a measure of geographic diversity.

Furthermore, as set forth in Section II.A.1. above, when a proposed site is located in the coastal zone as defined under the CZM Act, the project proponent must evaluate at least one alternative site and must provide a "justification of the necessity for or advantage of coastal siting along with an explicit definition of the process developed to compare alternative sites". 980 C.M.R. 9.02(1)(a). When a facility proposed for coastal siting is not coastally dependent, the alternative site to be proposed must be inland of the coastal zone. 980 C.M.R. 9.02(1)(a).

With respect to the CZM requirements, BECo has stated that its proposed project is not coastally dependent. By noticing the Ironstone site, BECo has complied with the requirement that the proposed alternative site be inland of the coastal zone. Further, as described above in Section II.C.2, the Company has also provided "an explicit definition of the process developed to compare alternative sites", as required by 980 C.M.R. 9.02(1)(a).

Finally, of the 61 sites evaluated by the Company in its site selection process, the Edgar site ranked first with respect to both environmental impacts and costs. The Company also considered the Edgar site to be advantageous for environmental permitting reasons, because it is an already existing utility site owned by BECo.

For the reasons stated above, the Siting Board finds that BECo has complied with the CZM requirement that its site evaluation and comparison "include a justification of the necessity for or advantage of coastal siting" for its proposed facility.

6. Conclusion on the Site Selection Process

The Siting Board has found that: (1) BECo has developed a minimally reasonable set of criteria for identifying and evaluating alternative sites; (2) BECo has appropriately applied its 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) BECo has identified at least two practical sites with a measure of geographic diversity.

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

D. Analysis of Proposed Facilities at the Primary Site

1. Environmental Impacts of the Proposed Facilities at the Primary Site

a. Air Quality

The Company asserted that facility emissions would fully comply with all federal and state air quality standards established to protect the public health and welfare and would have a minimum impact on ambient air quality in the vicinity of the Edgar site (BECo Initial Brief, pp. 231, 238, BECo Site Banking Brief, p. 49). BECo further asserted that the air quality impacts of the proposed facility would be adequately minimized consistent with the applicable environmental policies of the Commonwealth (BECo Initial Brief, p. 238).

The Company indicated that air pollutant emissions would result, primarily, from operation of the two combustion turbines, and, to a smaller degree, from the two auxiliary boilers, but stated that emissions would be controlled through the use of clean fuels and advanced air pollution technology (Exhs. BE-59, p. 6.1-1, BE-6, pp. 7-6, 7-7, BE-48, Tables AQ-37-1, AQ-37-2). The Company estimated the emission rate for each pollutant based on manufacturers equipment guidelines and fuel characteristics, noting that emissions would increase with oil firing (Exhs. BE-59, p. 6.1-3, Table 4.6-6, BE-48, p. AQ-1-1; Tr. 23, p. 34). BECo then estimated ambient air impacts for required averaging periods, assuming an annual plant capacity factor of 100 percent and fuel oil usage for the entire year (Exh. BE-59, p. 6.1-3).[77]

With respect to applicable regulations, BECo indicated that the operation of the proposed facility would be subject to federal air quality standards and regulations that are administered by the MDEP, including (1) National Ambient Air Quality Standards ("NAAQS"), (2) New Source Performance Standards ("NSPS"), and (3) Prevention of Significant Deterioration ("PSD") regulations (Exhs. BE-6, pp. 3-1, 3-2, 3-5, BE-48, summary, p. 6). The Company explained that the NAAQS are ambient ceilings for six criteria pollutants: (1) sulfur dioxide ("SO_2"); (2) particulate matter of ten micrometers or less ("PM-10");[78] (3) carbon monoxide ("CO"); (4) nitrogen oxides ("NOx"); (5) ozone;[79] and (6) lead, and were established to protect the

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77/ The Company stated that estimated emissions would exceed actual emissions due to its conservative assumptions -- 100 percent capacity factor and oil use (Exh. BE-59, p. 6.1-3).

78/ The Company indicated that NAAQS apply to PM-10 emissions, whereas Massachusetts regulations and PSD increments apply to emissions of total suspended particles ("TSP"), which include PM-10 (Exhs. BE-59, p. 5.2-5, BE-48, mitigation, p. 16). For purposes of this review, no distinction is made between PM-10 and TSP.

79/ The Company stated that ozone is not directly emitted from combustion sources, but instead, is produced in the ambient atmosphere by the interaction of volatile organic compounds ("VOC"), NOx and sunlight (Exh. BE-59, p. 2.4-1). Thus, to control ozone formation, the MDEP enforces emission restrictions public health and welfare (Exhs. BE-6, p. 3-1, BE-59, p. 2.4-1).[80] The Company further explained that the PSD regulations limit increases in ambient concentrations of criteria pollutants in areas where the existing air quality is in attainment of the NAAQS or unclassified with regard to the NAAQS, and also require that emissions of all criteria pollutants, as well as emissions of sulfuric acid mist and beryllium, be minimized (Exhs. BE-6, p. 3-2, BE-65, pp. 1-1, 2-2). The Company added that the NSPS are emission limitations for new or modified major sources of air pollution (Exh. BE-65, p. 3-2).

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on VOC's and NOx (id.).

80/ The Siting Board notes that, with respect to NAAQS, regions are categorized as attainment, nonattainment or unclassified for each criteria pollutant. Where existing air quality is in attainment or unclassified with respect to a specific pollutant, the Company would be required to demonstrate that ambient concentrations of that pollutant, which include facility impacts, would comply with the NAAQS. Where existing air quality is in nonattainment for a specific pollutant, a more stringent Offset and Nonattainment Review would be required if emissions of that pollutant were above a threshold level.

BECo indicated that the Weymouth area is in attainment or cannot be classified for NAAQS for all criteria pollutants with the exception of ozone (Exh. BE-59, pp. 5.2-3, 5.2-4, 6.1-5). The Company noted that the Weymouth area, as well as the entire state of Massachusetts, is classified as non-attainment with respect to ozone (Exh. BE-65, p. 2-2). With respect to VOC emissions, the Company noted that dispersion modeling was not required because the entire state of Massachusetts is classified as a nonattainment area with respect to the NAAQS for ozone Exh. BE-65, p. 2-2). The Company added that the requirements of an Offset and Nonattainment Review also were not applicable because the annual VOC emissions would be below the threshold level of 100 tpy (Exhs. BE-48, summary, pp. 3-4, AQ-31, AQ-32, BE-65, p. 4-1). The Siting Board notes that the VOC threshold will be reduced to 50 tpy under the 1990 Amendments to the Clean Air Act ("CAAA").

Additionally, the Company noted that a portion of the primary site is located in Quincy, which is classified as nonattainment for CO (Exh. BE-48, p. AQ-2-2; Tr. 53, pp. 78-79). However, the Company indicated that the MDEP has not required an Offset and Nonattainment Review for CO emissions in that the facility itself would be located in Weymouth (id.).

The Company stated that the proposed facility also would be subject to: (1) an MDEP policy limiting the ambient one-hour concentrations of NOx; (2) MDEP acid rain regulations limiting the emission rate of SO_2; and (2) MDEP guidelines limiting ambient concentrations of air toxics (Exhs. BE-48, p. AQ 1-1, BE-59, pp. 2.4-1, 6.1-16, and 6.1-17). The Company noted that MDEP review of its air pollution control plans and PSD application would encompass review of the aforementioned state and federal requirements (Exh. BE-6, p. 3-5).

The Company further noted that the operation of the proposed facility would be subject to provisions in the 1990 CAAA including a requirement that the Company obtain an allowance for each ton of SO_2 emitted, beginning in the year 2000 (Exhs. HO-E-2).[81] The Company added that forthcoming MDEP regulations would determine how other provisions of the CAAA, including provisions regarding NOx emissions, would apply to the proposed facility (Exh. HO-E-97; Tr. 53, pp. 82-83).

In this section, the Siting Board reviews the impacts of emissions of PSD regulated pollutants, air toxics and CO_2 from the proposed facility at the primary site as well as requests for a health risk assessment.

(1) PSD Regulated Pollutants

(a) Description

BECo indicated that PSD review of the proposed facility requires (1) a demonstration that best available control technology ("BACT")[82] would be incorporated into facility

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81/ The Company noted that it expects to transfer SO_2 allowances from its existing facilities to the proposed facility but that the precise mechanism for such transfers will be based on forthcoming regulations (Exh. HO-E-2).

82/ The Company indicated that a BACT analysis is the evaluation of potentially feasible emission control alternatives, beginning with the most stringent control alternative for each pollutant (Exh. BE-59, p. 2.4-2). BECo stated that a BACT determination would identify the most stringent control design in order to minimize emissions of SO_2, NOx, CO, PM-10, VOC, beryllium and sulfuric acid mist,[83] and (2) an analysis of the ambient air impacts of the proposed facility (Exh. BE-65, pp. 1-1, 2-2). With respect to the minimization of facility emissions, BECo stated that revisions to its fuel mix and combustion technology proposals over the course of the proceedings have resulted in reductions in anticipated facility emissions (Exhs. BE-48, AQ-3 through AQ-7, BE-65, sec. 4, HO-RR-93; Tr. 53, pp. 17-43).

With regard to fuel mix, the Company explained that natural gas has a minimal sulfur content and is essentially ash free (Exh. BE-65, pp. 4-6, 4-8, 4-12; Tr. 53, p. 19). Thus, BECo stated that emissions of SO_2, which are directly related to fuel sulfur content, would be reduced with increased use of natural gas and lower sulfur fuel oil, and emissions of PM-10, which are related to the ash content of fuel, also would be reduced with increased use of natural gas (id.).[84] BECo initially proposed to utilize natural gas for seven months with 0.3 percent sulfur oil for five months, but, during the course of this proceeding, in order to further minimize SO_2 emissions, the Company revised its proposal to use natural gas for 320 days and 0.2 percent sulfur oil for 45 days (Exhs. BE-6, sec. 6, BE-48, AQ-3 through AQ-10).[85]

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technology available, taking into account economic, environmental and energy factors (id.).

83/ The Company stated that although lead is also a PSD-regulated pollutant, emissions would be below the Environmental Protection Agency ("EPA") established threshold requiring PSD review (Exh. BE-59, p. 2-4.1).

84/ The Company noted that emissions of sulfuric acid and beryllium also would be reduced with increased use of natural gas and lower sulfur fuel oil (Exhs. BE-65, pp. 4-10, 4-12, BE-48, AQ-3 to AQ-7, p. 10).

85/ The Company noted that, even under its original fuel use proposal, SO_2 emissions would comply with all applicable NSPS and MDEP emissions limitations (Exhs. BE-65, p. 5.1, BE-59, In a recent revision of its BACT analysis submitted to MDEP on November 13, 1992, the Company recommended two further fuel mix options which would result in additional reductions in facility emissions: (1) use of natural gas for 365 days, with 0.2 percent sulfur oil as back-up for emergency periods only ("natural gas proposal"), and (2) use of natural gas for 320 days and use of 0.05 percent oil[86] for 45 days with an emission offset allowance for provision of making supplies available to a local gas distribution company ("LDC") ("emission offsets proposal") (Exh. HO-RR-93). The Company indicated that facility SO_2 and PM-10 emissions would be less under the natural gas proposal than under the emissions offsets proposal (id., Table 9, Table 16). However, the Company stated that under the emissions offset proposal, the Company could make available winter peaking supplies to an LDC and thus allow the LDC to add customers and increase gas sales (id., pp. 26 to 28).[87, 88] Based on potential customer conversion from oil to gas under this scenario, BECo estimated that reductions in area-wide SO_2 and PM-10 emissions from gas conversions would more than offset added facility emissions (id.).[89] The Company noted that the

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p. 6.1-17).

86/ Citing current uncertainties regarding production and supply logistics of 0.05 percent sulfur oil, the Company indicated that 0.2 percent sulfur oil would be substituted if the lower sulfur oil were not available (Exh. HO-RR-93, pp. 23-24).

87/ The Company indicated that, under this scenario, the LDC would share in the costs of constructing the natural gas pipeline to the site (Tr. 53, p. 17).

88/ The Company did not explain the basis for its expectation that the peaking supplies would result in increased gas sales, as opposed to replacing existing LDC supplies.

89/ The Company indicated that Boston Gas provided an estimate of the number of residential and commercial customers that would potentially convert from oil to gas (Exh. HO-RR-93, pp. 27-28).

emissions offset approach also would result in a net decrease in area CO emissions (id., Table ES-1).

The Company indicated that NOx emissions, which result from the combination of nitrogen in both the fuel and the combustion air with excess oxygen in the combustion air, could be minimized by combustion technology, such as reducing the temperature in the combustion chamber, as well as by post-combustion controls (Exh. BE-65, pp. 4-2, 4-3). BECo indicated that NOx emissions would be limited to no greater than 9 parts per million ("ppm") under each of the NOx emission control strategies considered (id., p. 5-1).[90]

In order to minimize NOx emissions, BECo first proposed use of both (1) steam injection into the combustion chamber to reduce peak flame temperature, and (2) selective catalytic reduction ("SCR") (id., p. 4-6). BECo noted that SCR is a post-combustion process whereby ammonia, injected into the exhaust stream in the presence of a catalyst, reacts with NOx to form nitrogen and water (id., p. 4-5).[91]

During the course of the proceedings, the Company proposed replacing the steam injection control design with a dry combustor technology, which would restrict flame temperature and corresponding NOx formation by controlling the quantity and distribution of air supplied to the combustion process, and which would reduce facility water requirements (Tr. 53, pp. 26-27;

90/ The Company noted that the NOx emission rate from the proposed facility would comply with the Northeast States Coordinated for Air Use Management ("NESCAUM") recommended guideline of 9 ppm, and would be well within the NSPS limitations of 101 ppm and 142 ppm for gas and oil firing, respectively (Exh. BE-59, p. 6.1-2).

91/ The Company noted that ammonia emissions would result from operation of the SCR (see Section II.D.1.a.(1)(b), below) (Exh. BE-65, p. 4-5).

Exh. HO-RR-93, p. 10).[92] The Company proposed use of two 110 MW turbine sets incorporating dry combustion ("dry combustion turbines" or "dry combustors") based on 320 days of gas-fired generation and 45 days of oil-fired generation with power augmentation and SCR ("base dry combustor design") (Exh. HO-RR-93, Table 4).[93] The Company indicated that emissions of NOx and ammonia combined would be 2.95 pounds per net kilowatt-year ("kWyr") with use of the base dry combustor design, compared to 2.87 pounds per net kWyr with the originally proposed steam injection control and SCR design (id.).[94]

In conjunction with its recently proposed natural gas and emission offsets BACT proposals, the Company considered several design options as BACT for NOx emissions, including the base dry combustor design (Exh. HO-RR-93, pp. 9-13).[95] With its natural gas proposal, BECo recommended that it achieve BACT for NOx through a new combustor design based on two 100 MW dry combustors with steam injection for power augmentation but without SCR (Exh. HO-RR-93). The Company indicated that this design would provide a NOx emission rate of 9 ppm or less, and would result in

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92/ The Company noted that dry combustor technology was not commercially available when the facility was originally proposed (Exh. BE-48, AQ-3 through AQ-7, pp. 13-19).

93/ The Company indicated that the dry combustor technology could provide a nominal water savings of approximately 486,000 gallons per day ("gpd") at a 100 percent capacity factor, but this would reduce the power output of the facility by 22 MW (Exh. BE-120, p. 2-2). Therefore, the Company indicated that steam injection would be utilized to provide offsetting power augmentation, and noted that steam injection would reduce the net water savings for the base dry combustor design to 135,000 gpd (id.). See Section II.D.1.e.(i), below.

94/ In evaluating the environmental impacts of the various NOx control strategies, the Company considered ammonia emissions as well as NOx emissions for the control strategies that include SCR (Exh. HO-RR-93, Table 6).

95/ The Company indicated that design options for reduction of NOx emissions included combustor type, combustor size, power augmentation and SCR (Exh. HO-RR-93).

NOx emissions of 2.26 pounds per net kWyr, the lowest NOx emissions in net kWyr of all alternatives considered (id., p. 16).[96]

The Company maintained that the natural gas proposal with 100 MW dry combustors and steam injection for power augmentation would not require SCR (id., p. 12). The Company explained that it would be possible to attain a NOx emission rate of 9 ppm or less without SCR, with 100 MW combustors and with exclusive use of natural gas (id., Tr. 53, p. 27).[97] The Company noted that inclusion of steam injection for 28 MW of power augmentation would require an additional 609,700 gpd of water compared to BACT alternatives based on (1) use of 100 MW dry combustors without power augmentation or SCR, and (2) use of 110 MW dry combustors with SCR (Exh. HO-RR-93, Tables 4 and 5). Finally, BECo asserted that dry combustion technology also would minimize emissions of CO and VOC, which result from incomplete combustion of carbon in the fuel (id., pp. 17-20).[98]

96/ The Company indicated that 100 MW combustors without steam injection for power augmentation would be the most stringent NOx control alternative producing the lowest NOx emissions in tons per year but that due to reduced efficiency, NOx emissions would be 2.37 pounds per net KWyr (Exh. HO-RR-93, pp. 14-16). The Company also indicated that the estimated facility emissions per net kWyr of NOx and ammonia combined would be lower under its proposed design than under all of the alternative designs included in BECo's revised BACT analysis (id., Table 4).

97/ The Company indicated that SCR could be eliminated from natural gas control strategies that include 100 MW combustors because a 9 ppm NOx emission rate has been guaranteed by a manufacturer for 100 MW combustors (Exh. HO-RR-93, pp. 11, 12). The Company added that SCR would be included with 110 MW combustors because current NOx emission rate guarantees are in the range of 15 ppm to 25 ppm (id.).

98/ The Company indicated that during the course of the proceedings, guarantees for CO emissions by combustion turbine manufacturers have consistently decreased and that it expects to achieve a CO emission rate of 4 ppm, which is less than current NESCAUM guidelines of 10 ppm (Exh. HO-RR-93, p. 18). The Company noted that it had evaluated installation of a CO catalyst but

In conjunction with the emission offset proposal, the Company also recommended that it achieve BACT for NOx through use of two 100 MW dry combustors with steam injection for power augmentation but noted that SCR would be required for oil firing periods (id., sec. 5). The Company estimated that facility emissions of NOx and ammonia combined under the emissions offset proposal would be 2.50 pounds per net kWyr, but that net area emissions of NOx and ammonia combined would be 0.88 pounds per net kWyr as a result of reductions associated with estimates of customer conversion from oil to gas (id., Table 13). By comparison, the Company estimated that net area emissions of NOx and ammonia combined under the natural gas proposal would be no less than the estimated facility emissions of 2.26 pounds per net kWyr (id., Tables 4, 13).

In order to predict the facility impacts with regard to ambient concentrations of SO_2, PM-10, NOx, and CO, the Company performed dispersion modeling analyses utilizing the emission rates from its originally proposed emission control strategy, based on seven months of gas-fired generation and five months of oil-fired generation (Exh. BE-59, pp. 6.1-2 to 6.1-4).[99] Specifically, BECo stated that it first performed a screening-level analysis using the Industrial Source Complex-Short Term ("ISCST") model over the range of operating loads and ambient temperature conditions to predict the worst-case impacts of the proposed facility and the approximate distances of predicted worst case impacts from the facility (Exh. BE-65, pp. 6.5-6.8). BECo stated that it then performed a

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determined that a CO catalyst, which also would increase CO_2 emissions, would not be a cost-effective means of further reducing CO emissions (Tr. 53, pp. 39-41).

99/ The Company indicated that modeling was performed assuming 100 percent oil-fired operation and use of 0.3 percent sulfur oil (Tr. 53, pp. 14-16). The Company indicated that it would perform an updated modeling analysis reflecting the proposed fuel mix when the emission control strategy was finalized, in conjunction with MDEP review (id.).

refined modeling analysis with five years of meteorological data 3using both the ISCST model and the COMPLEX I model[100] to predict facility impacts on existing air quality (id., pp. 6.8-6.14).[101]

The Company stated that its refined analysis demonstrated that ambient concentrations of SO_2 and PM-10 for all averaging periods would exceed EPA-defined significance levels (id., p. 7-2; Exh. HO-RR-109, p. 2).[102] The Company stated that, therefore, an identification of an AQAI and interactive source modeling would be required for SO_2 and PM-10 emissions (Exh. BE-65, p. 7-2). In addition, the Company stated that the one-hour NOx concentrations would exceed MDEP-defined significance levels, requiring modeling of existing background

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100/ The Company indicated that the ISCST and COMPLEX I models are used for differing terrain characteristics (Exh. BE-65, p. 6-8).

101/ The Company noted that sites located at or near the coastline may be subject to alternating land and sea breezes, which can occasionally elevate ground level concentrations (Tr. 23, pp. 107, 108, 110). At the request of the Secretary of Environmental Affairs, the Company also analyzed facility impacts with the MISRA-Shoreline Fumigation Model, which accounts for weather patterns specific to coastline locations (Exh. BE-73, p. 3). The Company indicated that the predicted facility impacts using this model were less than half the impacts predicted by the ISCST screening-level analysis (Exh. HO-RR-57A, p. AQ-3-1).

102/ The Company indicated that the EPA-defined significance levels establish a threshold level of air quality impacts (Exh. BE-65, Table 6-13, p. 7-2). The Company explained that, where facility impacts for specific pollutants for specific averaging periods would exceed the significance levels, identification of an air quality area of impact ("AQAI") and interactive source modeling would be required for that pollutant (id.). The Company further explained that an AQAI defines the extent of predicted significant air quality impacts of a specific pollutant and that it must be demonstrated that air quality standards will be maintained within the entire AQAI (id., p. 7-2).

concentrations (Exh. BE-65, p. 7-5).[103, 104] The Company further stated that annual NOx impacts and CO impacts for all averaging periods were below the significance levels, thus demonstrating compliance without further analysis (id.).[105]

The Company stated that its complete analysis, including background concentrations and interactive sources where applicable, demonstrated that ambient concentrations of all criteria pollutants would comply with NAAQS and PSD increments for all averaging periods as well as the MDEP one-hour NOx guideline (See Table 1) (Exh. BE-65, pp. 7-2 to 7-6).[106, 107]

Finally, BECo indicated that the maximum concentrations of beryllium would be below the PSD "de minimis" monitoring level and that maximum concentrations of sulfuric acid mist would comply with MDEP guidelines (id., pp. 7-6 and 7-7, Exh. BE-48, sec. AQ-1).

103/ The Company noted that the MDEP has established a significant impact level for one-hour NOx concentrations for administration of its one-hour NOx policy limitation (Exh. BE-65, p. 7-5).

104/ The Company noted that CO and NOx emissions would be higher during combustion turbine start-up than routine operation and, as such, predicted one-hour concentrations of CO and NOx based on start-up conditions (Exh. BE-65, pp. 7-5, 7-6).

105/ The Company indicated that although the predicted annual NOx concentration of 0.999 micrograms per cubic meter ("ug/m^3") was close to the significance level of 1 ug/m^3, air quality modeling included several conservative assumptions such that the actual NOx impact would thus be less than predicted levels under actual facility operation (Exh. BE-48, p. AQ-20-1).

106/ The Company maintained that the predicted 24-hour SO_2 concentration, which is close to the NAAQS, reflects conservative modeling measures (Exh. BE-48, p. AQ-21-1).

107/ BECo noted that increases in ambient concentrations of SO_2 and PM-10 would be less than five percent of the allowable PSD increases outside the AQAI's and not more than 50 percent of the maximum allowable increases inside the AQAI's (Exhs. HO-E-104, HO-E-105).

(b) Position of the Parties

The Attorney General argues that forthcoming changes in environmental protection policies and standards, including likely 1995 requirements for NOx emissions, as well as continuing technological developments, will require a new review of the air quality impacts of the proposed facility when the Siting Board considers the Company's final petition (AG Site Banking Brief, pp. 8-11). The Attorney General also argues that the Siting Board should restrict its review to only those aspects of the proposed facility that are certain and that would likely remain unchanged over the next ten years (id., p. 14).

BECo responds that there is little evidence that changes in air quality regulations will have a significant impact on the proposed facility, and moreover, regulatory changes identified by the Attorney General would likely be associated with existing facilities rather than new facilities (BECo Site Banking Reply Brief, pp. 4-5). BECo notes that it has requested preliminary approval of certain environmental aspects of the proposed facility and that final approval would involve a determination that the facility is in full compliance with the applicable regulations at that time (id., p. 5). Finally, BECo asserts that although potential further development of the dry combustor technology would lead to additional review, the record includes sufficient documentation for the Siting Board to evaluate the technology and determine its appropriateness for the proposed facility (id., pp. 6, 7).

(c) Analysis

Over the course of the proceedings, the Company has revised its emission control strategy with respect to fuel mix and combustion technology focusing on (1) increasing the use of natural gas and lowering the sulfur content of back-up fuel oil, primarily to address SO_2 and PM-10 emissions, and (2) incorporating combustion control technologies and post-combustion controls, primarily to address NOx emissions.

With these revisions, the Company has reduced expected emission rates for all criteria pollutants below initially proposed levels, with the exception that none of the Company's BACT proposals would guarantee a further reduction of the 9 ppm NOx emission rate initially proposed. The Siting Board notes that while the choice of a strategy for NOx control would not significantly impact the NOx emission rate, it would directly affect emissions of other substances as well as facility water requirements.

With regard to the first of BECo's most current BACT recommendations for fuel mix and combustion control technology -- use of two 100 MW dry combustors, steam injection for power augmentation and no SCR, combined with 365 days of gas-fired generation and use of 0.2 percent sulfur oil for emergency back-up -- the Siting Board recognizes the benefits of using natural gas for the entire year and eliminating the need for the SCR system, thereby avoiding ammonia emissions and safety concerns associated with the storage and transportation of ammonia. (See Section II.D.1.i.(2) below). In addition, the Company's BACT recommendation would result in combined emissions of NOx and ammonia totalling 2.26 pounds per kWyr, while the Company's earlier proposal -- use of two 110 MW combustors, power augmentation and SCR, with operations based on 320 days of gas-fired generation and 45 days of oil-fired generation -- would result in combined emissions of NOx and ammonia totalling 2.95 pounds per kWyr.

However, BECo has not fully addressed a number of significant issues or trade-offs between environmental impacts associated with its recommended approach, including the substantial increase in water requirements relative to options without steam injection for power augmentation and the control of NOx emissions if oil is fired during an emergency. In addition, the Company has not explored the potential to reduce the NOx emission rate below the NESCAUM guideline of 9 ppm by including SCR with the proposed combustors.

The Company's second current BACT recommendation incorporating emission offsets -- that is, use of two 100 MW dry combustors, with operations based on 320 days of gas-fired generation and 45 days of oil-fired generation utilizing 0.05 percent sulfur, steam injection for power augmentation, and SCR during oil firing periods only -- would result in facility emissions of NOx and ammonia totalling 2.50 pounds per kWyr, slightly higher than BECo's natural gas BACT recommendation. In addition, the emissions offsets BACT recommendation would increase facility SO_2 and PM-10 emissions over the option of using natural gas for 365 days. Nonetheless, the Siting Board recognizes that the alternative BACT recommendation could provide benefits through the potential reduction of all criteria pollutants in the vicinity of the proposed facility, even with added facility emissions. Such reductions could result from anticipated customer conversions from oil to gas made possible by an LDC sharing in the Edgar pipeline capacity.

The Siting Board previously has recognized the potential benefits of an emissions offset approach in ensuring a least-cost, least environmental impact energy supply for the Commonwealth by providing a greater return in environmental protection without increasing costs. Eastern Energy Corporation, 25 DOMSC 296, 341-346 (1992) ("EEC Compliance"). In addition, the Siting Board recognizes the potential benefits in reducing background concentrations in an area such as the vicinity of the primary site, where existing measured background concentrations of criteria pollutants are already in excess of 50 percent of NAAQS (See Table 1, attached). However, the Company has not provided adequate documentation to either (1) support its estimation of potential area-wide emissions reductions, or

(2) ensure that emissions reductions would occur in the immediate area of the proposed facility.[108]

Further, as a threshold matter in previously accepting emissions offsets as a means of minimizing facility emissions, the Siting Board first considered whether or not the increased emissions at the site would be acceptable. EEC Compliance, 25 DOMSC at 341-346. Here, the Company has provided an analysis of predicted facility impacts based on fuel that is no longer being considered -- fuel oil with 0.3 percent sulfur content -- and has not yet updated its analysis of facility impacts to account for recent fuel use proposals. Although the Company's analysis of facility impacts demonstrated that ambient impacts for all PSD-regulated pollutants would be below respective NAAQS, the modelled ambient impacts are nonetheless high -- greater than 60 percent of NAAQS for all of the modelled criteria pollutants and averaging periods, and greater than 90 percent of NAAQS for twenty-four hour SO_2 and annual PM-10 (See Table I).[109] The Siting Board recognizes that existing background concentrations are significantly greater than the additional facility contributions estimated by the Company, and further that the actual facility impacts under either of the Company's current BACT recommendations would be less than the Company's estimates of ambient impacts. However, such reduced impacts have not been quantified by BECo and thus, the Siting Board cannot fully evaluate the trade-offs between BECo's two BACT recommendations

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108/ The Company also has not addressed increased water requirements or potential reduction in NOx emissions below 9 ppm in this proposal.

109/ The Siting Board notes that in EEC, facility impact combined with background concentrations was greatest with respect to the 24-hour SO_2 concentration, but that such impact was 48 percent of NAAQS (22 DOMSC at Table 7).

or determine, at this time, whether facility impacts would be minimized by use of natural gas for 320 or 365 days.[110]

The Siting Board further recognizes emission control technology is continually evolving. In fact, emission control technology has advanced over the course of the proceeding; technologies that were not commercially available at the start of the proceedings (i.e., dry low NOx combustors) are now commercially available with guarantees for low emission rates. It is likely that emission control technology will continue to progress and that technologies not available at this time will be available when BECo files its final petition. For instance, should dry combustors with an output of 110 MW become available with appropriate NOx emission limitation guarantees, BECo would have more flexibility to achieve its proposed power output through a dry combustor technology, while addressing the trade-off between incorporating steam injection for power augmentation and saving associated water requirements of over 600,000 gpd.

Finally, the Siting Board recognizes that under either of BECo's BACT recommendations, air quality impacts would comply with existing federal and state air quality standards. However, compliance with existing air quality standards is a minimum threshold for purposes of the Siting Board's siting review. If air quality standards were not met by the Company's proposal, the Siting Board would not even consider proceeding with site banking in this docket at this time.

Siting Board review extends beyond a checklist of existing regulatory standards of other agencies. See EEC, 22 DOMSC at 336-337. Siting Board review considers the interactive effects between environmental impacts as well as the interrelationship among environmental impacts, cost and reliability in determining

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110/ The Siting Board notes that emissions of air toxics would also be affected by the Company's choice of fuel mix. See Section II.D.1.a.(2)(a), below.

whether the environmental impacts of a facility have been adequately minimized. Id.

Here, BECo has continued to explore alternative emission control strategies to further reduce emissions as technology has evolved. However, in considering alternative emission control strategies, BECo has not fully evaluated all of the trade-offs in environmental impacts that would occur in implementing either of its currently proposed emission control strategies, nor has the Company provided sufficient documentation regarding its emissions offsets proposal for the Siting Board to evaluate its potential. In addition, considering the unknown time-frame of facility construction, technology that is not commercially available at this time could potentially be available to further minimize impacts and the Siting Board expects that the Company will continue to evaluate emission control strategies in light of technological advancements.

Thus, it would be premature at this time for the Siting Board to determine whether the BECo has established that the impact of facility emissions of the PSD-regulated air pollutants would be minimized under any of its proposals or BACT recommendations. At such time as the Company presents its filing for final approval of the project, the Siting Board will evaluate fully whether the Company has minimized air quality impacts while considering the interactive effects between environmental impacts, and the balance between environmental impacts and cost.

(2) Toxic Pollutants

(a) Description

Based on a literature search and consultation with a combustion turbine vendor, BECo identified the following toxic pollutants that potentially would be emitted from the proposed facility due to their presence in fuel oil: beryllium, cadmium, chlorine, chromium, copper, fluoride, lead, mercury, nickel, vanadium, formaldehyde, hydrogen chloride, and sulfuric acid

(Exh. BE-48, p. AQ-1-2).[111] BECo noted that for each of these substances, emissions from oil combustion would exceed those from natural gas combustion (id.) In addition, the Company indicated that ammonia emissions would result if the SCR process is used to reduce NOx emissions (id., p. 4.6-5).[112]

BECo calculated ambient air quality impacts of each of the aforementioned toxic pollutants based on 100 percent fuel oil firing (id. pp. AQ-1-1 through AQ-1-4). The Company stated that the 24-hour and annual concentration of each toxic pollutant would be below its respective 24-hour Threshold Effects Exposure Limit ("TEL") and annual average Allowable Ambient Limit ("AAL"), demonstrating compliance with the MDEP Air Toxics Assessment Guideline (id.).[113]

WATER argues that emission rates for beryllium, cadmium, chromium and formaldehyde were predicted through fuel sample analysis, but were not modeled or added to existing ambient air concentrations (Carey Brief, p. 3). WATER argues that, therefore, it cannot be determined if the impact of predicted emissions of these substances would exceed the AAL's and TEL's (id.).

WATER further argues that the proposed facility has the potential to emit additional toxic pollutants that are suspected

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111/ The Company indicated that the MDEP has reviewed the Company's list of potential toxic emissions and has not required an analysis of any additional substances (Exh. BE-48, p. AQ-1-1).

112/ The Company explained that ammonia emissions result from "ammonia slip," the excess ammonia which passes through the catalyst bed without reacting with NOx (Exh. BE-59, p. 4.6-5). The Company stated that the SCR vendor has guaranteed an ammonia slip rate of seven ppm when firing natural gas and ten ppm when firing fuel oil (id.). These rates would comply with MDEP ammonia slip guidelines (Tr. 23, p. 42).

113/ The Company stated that toxic pollutant emission rates were based on conservative assumptions, including year-round oil firing and overestimation of toxic concentrations in fuel oil, and therefore, impacts were overstated (Exh. BE-48, pp. AQ-1-2 through AQ-1-4).

or known carcinogens including benzene, ethylene compounds including toluene, arsenic, and benzo-a-pyrene and other polycyclic aromatic hydrocarbons ("PAH") (id., p. 4, citing Exhs. WAT-RR-8, WAT-RR-19). WATER asserts that BECo has not quantified the emissions of these substances and that, unlike the minute quantities that the Company claims for other air toxins, emissions of benzene, ethylene compounds, and PAH's could potentially be high (Carey Brief, pp. 4-5).[114] Finally, WATER states that recent measurements of ambient levels of benzene and ethylene compounds in the vicinity of the proposed facility demonstrated that TEL's and AAL's were currently exceeded (id. pp. 7-8, citing Exh. WAT-15).[115]

In response to WATER, the Company stated that all toxic emissions would comply with the MDEP's air toxics assessment guideline, and that, further, virtually every substance analyzed would be emitted below minimum measurement detection limits (BECo Initial Brief, p. 273). With regard to arsenic and PAH emissions, the Company responded that (1) arsenic is generally not a constituent of 0.2 percent sulfur distillate fuel;[116] (2) PAH's are normally found in residual rather than distillate

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114/ WATER notes that VOC emissions, which include benzene and ethylene compounds, were estimated to be approximately 56 tpy (Carey Brief, p. 5, citing Exhs. BE-48, Table AQ-37-2, WAT-11, WAT-RR-8). In addition, WATER noted that unburned hydrocarbon emissions include PAH's (Carey Brief, p. 5). Water stated that unburned hydrocarbon emissions were estimated to be 240 tpy based on oil burning for 45 days and that such emissions would be higher when burning natural gas than when burning oil (Carey Brief, p. 5, citing Exh. BE-59E, sec. F.3).

115/ WATER noted that recent ambient air modeling in Weymouth, Braintree and Quincy, which included monitoring at the site of the proposed facility, revealed ambient concentrations of benzene in excess of AAL's and TEL's, and ambient concentrations of toluene in excess of AAL's (Exh. WAT-15; Tr. 39, p. 127).

116/ The Company indicated that arsenic was not a constituent of any distillate oil samples analyzed (Tr. 23, p. 45).

fuels; and (3) any emissions of either arsenic or PAH's would be negligible (Tr. 23, pp. 41, 45).[117]

(b) Analysis

The record demonstrates that toxic pollutant emissions from the proposed facility would be greater with oil combustion than natural gas combustion. The record further demonstrates that BECo's estimation of the emission rates and impacts of toxic substances was based on 100 percent fuel oil firing. Thus, even though BECo has demonstrated that ambient concentrations of all air toxics would comply with state standards, such concentrations would be greatly reduced by either of the Company's current fuel mix proposals, use of natural gas for either 320 or 365 days. In addition, if BECo successfully develops and implements a plan to eliminate SCR or to restrict its use to oil-fired periods, ammonia emissions would be reduced. The majority of WATER's concerns would be addressed by a reduction in emissions of air toxics.[118]

In comparing the impact of each of the Company's emission control strategies on the emission of toxic pollutants, the Siting Board notes that utilization of gas for 365 days and elimination of the SCR system would minimize facility emissions to the greatest extent possible, but conversion of oil customers to gas under an emissions offset approach could reduce area-wide emissions even further. Inasmuch as BECo has not finalized an emissions control strategy, and for the reasons enumerated in

117/ The Company stated that the combustion turbine vendor predicted maximum PAH emissions of less than one ppm for natural gas firing and less than five ppm for distillate oil firing (Exh. WAT-RR-19).

118/ With regard to WATER's comments regarding the lack of ambient background modeling for beryllium, cadmium, chromium and formaldehyde, the Siting Board notes that there is no evidence that MDEP regulations require modeling of ambient background concentrations to demonstrate compliance with AAL's and TEL's, nor have we ever required such modeling.

Section II.D.1.a.(1), above, it would be premature for the Siting Board, at this time, to determine whether the impact of facility emissions of air toxic pollutants has been minimized. At such time as the Company presents its filing for final approval of the project, the Siting Board will evaluate fully whether the Company has minimized air quality impacts while considering the interactive effects between environmental impacts, and the balance between environmental impacts and cost.

(3) Carbon Dioxide

(a) Description

BECo indicated that 830,000 tpy of CO_2 would be emitted from the proposed facility (Exh. HO-E-98).[119] The Company stated that the efficient generating technology of the proposed facility, with natural gas as the predominant fuel, would maintain CO_2 emissions at a minimum level (id.). BECo added that there are no readily available control technologies that would further reduce CO_2 emissions and that there are currently no applicable requirements to control CO_2 emissions (id.).

In addressing the impact of CO_2 emissions, BECo stated that it has not considered participation in state-sponsored programs to offset facility CO_2 emissions, such as the Massachusetts ReLeaf Program (Exh. HO-E-5). However, BECo stated that its Company-wide programs and policies, including implementation of demand side management ("DSM"), promotion of electric vehicles, increased utilization of natural gas and continued use of nuclear and hydroelectric power, have a direct impact on total Company CO_2 minimization (Exh. HO-E-98). For example, the Company estimated that its energy savings resulting

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119/ The Company calculated CO_2 emissions based on (1) natural gas firing for 320 days, oil firing 45 days, and (2) plant capacity factor of 60 percent (Exh. HO-E-98). The Siting Board notes that emissions of all other pollutants was based on a plant capacity factor of 100 percent. See n. 76, above.

from 1991 DSM programs have avoided 190,825 tons of CO_2 emissions (id.).

(b) Analysis

In Enron, the Siting Council first established a requirement that all applicants of proposed facilities that emit CO_2 must comprehensively address the mitigation of CO_2 (23 DOMSC at 195-196). In that decision, the Siting Council accepted a specific CO_2 mitigation cost commitment for the project without setting forth a guideline or standard for determining the adequacy of CO_2 mitigation. Id.

The Siting Council next addressed CO_2 mitigation in the EEC Compliance, 25 DOMSC at 348-367. In approving a specific cost commitment for the project, the Siting Council set forth general criteria it would consider in order to determine the appropriate level of CO_2 mitigation for a proposed facility. Id., at 365. Specifically, the Siting Council stated that it would consider various relevant project factors including facility cost, facility CO_2 emissions and any increment of such emissions exceeding the emissions of backed out capacity. Id. In addition, the Siting Council stated that it would address the adequacy of CO_2 mitigation in terms of the quantity of CO_2 emissions offsets to be attained rather than in terms of the cost to be committed for providing CO_2 emission offsets. Id., at 362. Further, the Siting Council provided that future applicants must present alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verification of estimated results, to demonstrate that all cost-effective approaches have been adequately considered. Id., at 360.

Here, BECo has asserted that certain Company-wide programs and policies have a direct impact on CO_2 minimization, but BECo has not provided a specific proposal to offset the CO_2 emissions of the proposed facility nor has the Company provided an analysis of alternative CO_2 mitigation plans specific to the proposed facility.

The Siting Board notes that the Company's application predates both of the aforementioned decisions. Thus, the requirements set forth in both of these decisions were not addressed by BECo in its filing. Further, for reasons outlined below, a specific proposal to offset the CO_2 emissions of the proposed facility would be more appropriately addressed within the context of the Company's final petition than in the instant site banking review.

First, the Siting Board recognizes that the general criteria to determine the adequacy of a CO_2 mitigation proposal, set forth in the EEC Compliance, 25 DOMSC at 358-367, will continue to evolve as the Siting Board addresses this issue in petitions that will be decided before BECo files its final petition. Thus, further precedent will be established to assist BECo in developing a proposal that would adequately minimize CO_2 emissions. Second, issues that are necessary to determine the adequacy of a CO_2 mitigation proposal, such as the relationship of CO_2 mitigation to overall facility cost and the impact of proposed and increased levels of CO_2 mitigation on project viability would be addressed in the final review of the proposed facility rather than the site banking review.

Accordingly, it would be premature for the Siting Board, at this time, to determine whether or not the impact of CO_2 emissions from the proposed facility has been minimized. In order to address minimization of CO_2 emissions, the Company shall include in its final petition, (1) a proposal to comprehensively address the CO_2 emissions from the proposed facility, and (2) alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verifications of estimated results in order to demonstrate that all cost-effective approaches have been adequately considered. At such time as the Company presents its filing for final approval of the project, the Siting Board will evaluate fully whether the Company has minimized air quality impacts while considering the interactive effects between environmental impacts, and the balance between environmental impacts and cost.

(4) Health Risk Assessment

During the course of this proceeding, both WATER and Weymouth have argued that operation of the proposed facility would have unacceptable health impacts. In this section, the Siting Board reviews these and related Company arguments and supporting documentation to determine if a health risk assessment is appropriate.

BECo asserts that, by complying with the NAAQS, the proposed facility poses no health threats to the nearby population and, as such, a health study should not be required as a condition for approval of the proposed facility (BECo Initial Brief, p. 274; see Exh. BE-86). The Company emphasized that primary NAAQS seek to prevent pollution levels that are known to be harmful, as well as lower pollution levels that could pose an unacceptable risk (Exh. BE-48, summary p. 5-6). BECo added that, in setting the primary NAAQS, the EPA has considered such factors as "the nature and severity of the health effects involved, the size of the sensitive population(s) at risk and the kind and degree of the uncertainties that must be addressed" (id.). In addition, BECo stated that AAL's were established by the MDEP based on potential adverse health effects of chemical substances (Exh. BE-86).

BECo further stated that its position that the proposed facility will not adversely affect public health is further justified by the Company's use of conservative operating assumptions which overestimated facility impacts (Exh. BE-48, summary, pp. 6-7). BECo stated that actual facility emissions will comply to a greater degree with ambient air quality standards than predicted emissions (id.).

Finally, the Company notes that (1) the Secretary of the Executive Office of Environmental Affairs has determined that a discrete health risk assessment "would not provide significant additional information"; (2) the Siting Council did not require a health risk assessment in the case of a proposed coal-fired facility; and (3) BECo has agreed to provide funding for a health study, should the proposed project go forward (BECo Initial Brief, pp. 273-274; see Exhs. BE-73, HO-RR-57A, sec. IV, WEY-21). BECo indicated that even though facility construction has been deferred, it would not be willing to finance a health study prior to receiving construction funding due to the high cost of such a study (Exh. HO-E-99).

WATER asserts that the proposed facility has the potential to adversely impact the health of residents in its vicinity and that therefore, the construction of the proposed facility at the Edgar site should not be approved without a study of (1) the health status of the population around the Fore River Basin, and (2) the relation of existing industries to the health status of the population (Carey Brief, pp. 1, 9).

WATER argued that the record demonstrates that the health status of residents in the vicinity of the proposed site is already burdened due to elevated rates of respiratory illnesses in comparison to statewide averages (id., p. 1). In support, WATER referred to two Massachusetts Department of Public Health studies entered into the record by the Weymouth Board of Health ("WBH") which relate to the health status of Quincy, Braintree and Weymouth residents (Exhs. WBH-1, p. 2, WBH-2, WBH-3). WATER stated that these studies suggest that residents in the vicinity of the primary site have an excess of respiratory problems (id.).[120]

120/ The two studies were (1) a 1990 site suitability study for a proposed Clean Harbors of Braintree, Inc. incinerator ("CHBI Study"), and (2) a 1989 study of lung cancer incidences in Quincy, Weymouth and Braintree ("LCI Study") (Exhs. WBH-2, WBH-3).

The CHBI Study analyzed the health status and demographics of the population in the vicinity of the proposed incinerator site in order to determine the extent of sensitive receptors near the site (Exhs. WBH-1, p. 2, WBH-2). Weymouth witness, Dr. Knorr, explained that sensitivity refers to increased

In response to the Company's position that the proposed facility would not have adverse health impacts because air pollutant emissions would meet standards designed to protect public health, WATER referred to testimony of Dr. Knorr (Carey Brief, pp. 2-3). Specifically, Dr. Knorr stated that although the primary NAAQS were established at a level to protect health within an adequate margin of safety, these standards do not necessarily protect the most sensitive group of individuals against health effects and are not necessarily applicable or sufficient where there is evidence that a burdened or sensitive population would be impacted by pollutant emissions (Tr. 39, pp. 27-30; Exh. BE-81).

In addition, WATER asserts that BECo has not assessed the cancer risk of facility emissions on the residents of the Fore River Basin (Carey Brief, p. 4). WATER argues that a number of air toxins that will be emitted are suspected or known carcinogens and that the effect of exposure to multiple carcinogens is unknown (id., citing Exh. WAT-10). WATER argues that, therefore, the impact of predicted emissions of toxins on the sensitive and general population is not known (Carey Brief, pp. 3-4). WATER further maintains that additional known or suspected carcinogens would be emitted from the proposed facility, such as benzene, arsenic, benzo-a-pyrene and ethylene

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susceptibility to a pollutant, resulting in adverse health effects (Exh. BE-78). The CHBI Study found that residents of Quincy and Weymouth have greater respiratory disease rates than the state as a whole, and that there is a sensitive population living in close proximity to the site of the proposed incinerator (Exh. WBH-2). Dr. Knorr stated that the results of the CHBI Study would be applicable to the Edgar site since it is located within a mile of the CHBI site and the census tract of the proposed facility site was included in the CHBI study (Tr. 39, p. 9).

The LCI Study, which analyzed lung cancer rates in the three municipalities, found that lung cancer rates were elevated in a number of census tracts in each community and that several of these census tracts border the Weymouth Fore River area (Exh. WBH-3).

compounds, but that such emissions have not been quantified by BECo, making it impossible to assess their potential impact (id., p. 4).

As noted above, Weymouth and the Company have entered into an agreement which includes health issues (see Section I.B., above). The agreement stipulates that BECo will provide (1) a maximum of $30,000 for the preparation of a study of options for protocols to determine the health status of residents of the area, prior to receipt of all regulatory approvals and commencement of construction of the proposed facilities at the Edgar site,[121] and (2) $650,000 for the preparation of a health study, after commencement of construction and construction loan funding becomes available (Exh. WEY-21, pp. 7-8).[122] Nonetheless, Weymouth suggests that the Siting Board require the Company to make its gift of $650,000 to Weymouth, at the time construction loan financing is secured, for the purposes of a health study or other appropriate purpose(s) as determined by the WBH (Weymouth Site Banking Brief, p. 6).

121/ Weymouth admits that the Company has already provided the funding for the preparation of an options study regarding health study protocols (Weymouth Site Banking Brief, p. 6).

122/ In the Agreement, Weymouth and BECo both acknowledged that: (1) there has been a concern about the health conditions of Quincy, Weymouth and Braintree citizens; (2) BECo has been requested to conduct a health study as a part of the licensing process for the proposed facility; (3) BECo has maintained that a health study would not be necessary since health effects are considered in the formulation of standards and regulations with which the proposed facility would comply; (4) facility emissions would be below any existing or currently planned fossil fuel electric power plant in New England; (5) the Secretary of Environmental Affairs has found that a discrete health risk assessment would not provide significant additional information; and (6) an accurate representation of the health in the three communities would be of general benefit to the local Boards of Health and that the three communities are unlikely to be able to fund such a study (Exh. WEY-21, pp. 6-7).

The record demonstrates that, based on two previous studies of the health status of the residents of Quincy, Weymouth and Braintree, rates of respiratory illnesses in certain areas of these communities are elevated in comparison to statewide averages. The record also indicates that BECo has agreed to provide Weymouth with substantial funds, for the preparation of a health study in the event the project receives all final approvals and construction loan funding becomes available.

Further, with regard to WATER's concerns relating to the potential emission of toxic pollutants that are suspected or known carcinogens on both the general and sensitive population, the record demonstrates that emissions of such pollutants would result primarily from fuel oil firing and that BECo has proposed significant reductions in fuel oil firing during the course of this proceeding (see Section II.D.1.a.(1)(a), above). The Siting Board recognizes that the level of fuel oil BECo will be permitted to burn will be a function of its final air permit. However, the likely reduction in fuel oil use and the consequent reduction in the potential impact of toxic pollutants should alleviate some of WATER's concerns in this area.

Nonetheless, in light of the evidence regarding the health status of residents in the communities surrounding the proposed facility,[123] the Siting Board recognizes further that a health study would be beneficial to the community. The Siting Board recognizes that a comprehensive health study may require an extended time-frame to complete. However, results of a health study would be most beneficial if they were available as close as possible to the initial operation of the proposed facility. Even though Weymouth has agreed to a delay in BECo's funding of the health study until construction loan financing is secured, the

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123/ The Siting Board notes that, in addition to evidence regarding health status of residents, existing background concentrations of most criteria pollutants in the vicinity of the proposed facility are in excess of 50 percent of NAAQS (see Table I) (see Section II.D.1.a.(1)(a), above).

Siting Board finds that it would be more appropriate for the Company to provide initial funding to Weymouth at the time the Company files its final petition with the Siting Board.

Accordingly, based on the foregoing, the Siting Board requires the Company to provide its share of funding for the preparation of a health study, in a manner consistent with the agreement between BECo and Weymouth, except that BECo shall provide a sufficient portion of such funding in an earlier payment or series of payments, as may be further agreed by BECo and Weymouth, to allow the health study to proceed according to a reasonable schedule beginning at the time BECo files its final petition for construction of the proposed facilities with the Siting Board.

The Siting Board recognizes that, in this instance, we have modified the terms of an agreement reached between BECo and Weymouth. The Siting Board is sensitive to the efforts involved in reaching such settlement, and is supportive of the pursuit of settlement agreements, generally, as a means of resolving conflicting concerns of parties in siting reviews. Here, however, we are persuaded that such modification is appropriate.

(5) Conclusions on Air Quality

With respect to the impacts of facility emissions of PSD-regulated air pollutants, air toxic pollutants and CO_2, the Siting Board has concluded, based on the reasons set forth in the above sections, that it would be premature for the Siting Board, at this time, to determine whether impacts from the facility emissions have been minimized. Therefore, the Siting Board finds that the Company has not provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to air quality for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to air quality.

As part of the Company's final petition, the Siting Board expects that the Company would include a revised air quality analysis which 1) takes into account the most current emission control strategy as well as the air quality regulations and standards in effect at the time of filing, and (2) provides clear documentation of estimates of offsets related to provision of gas supplies to an LDC. In addition, in order to address minimization of CO_2 emissions in the final petition, the Company shall comply with the condition to include in its final petition, (1) a proposal to comprehensively address the CO_2 emissions from the proposed facility, and (2) alternative CO_2 mitigation plans, including likely arrangements for ensuring implementation and verifications of estimated results in order to demonstrate that all cost-effective approaches have been adequately considered. Finally, with respect to the preparation of a health study, the Company shall comply with the condition to provide Weymouth with funds for the preparation of a health study at the time it files its final petition for construction of the proposed facilities with the Siting Board.

Accordingly, based on the foregoing, the Siting Board makes no finding regarding whether the environmental impacts of the proposed facility at the primary site with respect to air quality have been minimized.

b. Surface Water Quality/Wetlands

(1) Description

The Company indicated that apart from wetlands associated with the immediate shorefront and waters of the Weymouth Fore River, there were no other identifiable wetlands at the immediate primary site (Exh. BE-67, pp. 24-25).[124]

124/ However, BECo indicated that a total of 5.2 acres of wetlands would be impacted in the clearing of a right-of-way ("ROW") for the lateral gas line to the primary site (Tr. 56, p. 135). Of the 5.2-acre total, 3.7 acres would be permanently impacted, and the remaining 1.5 acres would serve as temporary workspace during the laying of the pipeline and be allowed to revert to pre-existing conditions (Tr. 56, p. 135). BECo has obtained an Order of Conditions issued by the Weymouth

The Company stated that potential impacts of the proposed facility on water quality relate to construction activities, especially dredging, and to cooling water intake and thermal discharge during facility operation (Exh. BE-6, p. 7-12). The Company asserted that dredging activity would not have an adverse impact on water quality (BECo Initial Brief, pp. 247-248). The Company further asserted that the cooling water intake and thermal discharge for the proposed facility would have minor impacts on water quality, based on the proposed engineering design and intake location (id., p. 248).

In support of its waterways analysis, the Company indicated that it had compiled data tracking the history of water quality and aquatic ecology for the Weymouth Fore River, and conducted a one-year sampling program to further identify the type, quality and quantity of aquatic species in the river (Exhs. BE-6, pp. 7-2 to 7-4, BE-59, p. 5.3-1). With respect to water quality, the Company stated that the Weymouth Fore River is designated as Class SB coastal and marine waterway suitable for protection and propagation of fish and other aquatic life (Exh. BE-59, p. 5.3-1). The Company noted, however, that from time to time the river has exceeded applicable water quality limits for its class (id.). With respect to aquatic ecology, the Company stated that investigations of benthic invertebrates, ichthyoplankton and finfish establish that the Weymouth Fore River contains a diverse community of marine organisms typical of a northern coastal estuary (id., p. 5.3-2). The Company further indicated that the Weymouth Fore River is an unsuitable habitat for rare or endangered aquatic species and that no rare or endangered aquatic species were identified during its investigations (id., pp. 5.3-2 to 5.3-9).

Conservation Commission (Exh. WEY-15). WATER has asserted that it has filed an appeal with the DEP regarding the Order of Conditions (WATER Site Banking Brief, p. 5).

The Company stated that it would dredge approximately 8,500 cubic yards of river bottom material and install approximately 325 linear feet of riprap embankment in the vicinity of the new intake structure (Exh. BE-6, p. 7-15). In addition, the Company indicated that additional dredging could be required for installation of the lateral gas pipeline by Algonquin across the Weymouth Fore River (id.; Exh. WEY-36).[125]

The Company stated that the dredge volume removed would represent a minute change in the estuary's tidal volume, while the riprap and intake structure installation would occupy only a small fraction of the Weymouth Fore River tidal flats (id.). The Company indicated that proposed dredging would not extend into the Fore River Basin (Exh. WEY-36). The Company testified that while it expects dredging would affect shellfish beds, it would mitigate any such impacts in accordance with requirements of those state and federal agencies with supervisory authority (Tr. 51, p. 36). The Company expected to complete dredging in three to five months (Exh. HO-E-27).

With respect to water quality impacts of dredging, the Company reported that its sediment sampling established that bottom material in the dredging area are clean, and that therefore the proposed dredging would have no adverse effect beyond a local temporary increase in turbidity (Exhs. BE-6, p. 7-215, BE-48, p. WQ-4). The Company indicated that its sampling showed lower contaminant concentrations than available results of other dredge sample studies because the other studies relied on surface sediment grabs which were heavily influenced by recent historic industrial uses of the Weymouth Fore River (Exh. HO-RR-57A, p. D-1-2). The Company indicated that its own samples mixed surface sediment with deeper sediments, resulting in lower levels of some contaminants (id., Table D-1-1,

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125/ Algonquins's filing with FERC set forth two options for the Weymouth Fore River crossing; dredging (trenching and recover) or directional drilling (Exh. HO-E-102, pp. 8, 9).

pp. D-1-1, D-1-2). The Company contended that the samples of its study were more meaningful than were the samples of the surface studies because they reflected both typical clam shell dredging operations in the Weymouth Fore River and the type of dredging to be undertaken for the proposed facility (id., p. D-1-2).

The Company stated that facility effluent would be composed principally of cooling water and boiler blowdown (Exh. BE-48, p. WQ-6). BECo reported that use of chlorine for biofouling control would result in discharge of residual chlorine to the Weymouth Fore River in the cooling water (Exh. HO-RR-54). The Company stated that all facility effluents, including chlorine, would (1) be subject to NPDES permit limitations, and (2) meet EPA criteria in the receiving waters (Exh. BE-48, pp. WQ-6, WQ-8).

With regard to other potential effluents, the Company indicated that a multiple system of safeguards would prevent inadvertent release of pollutants from the proposed facility into the Weymouth Fore River (Exhs. BE-59, pp. 3.1 to 3.1-11, HO-E-73). The Company stated that the proposed system would provide treatment of demineralizer regenerant plant waste and equipment and floor drain wastewater, as well as neutralization of HRSG blowdown (id.). The Company noted that the pollutants would then be forwarded to a holding tank for low volume waste where continuous pH and flow monitoring would be provided (id.).

With regard to thermal impact, the Company indicated that the proposed facility would be operated using a once-through cooling system with a flow of 113,000 gallons per minute ("gpm") and a temperature increase of 12 degrees Fahrenheit ("F") (Exh. BE-6, p. 7-12). The Company stated that the mixing zone for the proposed discharge would not intersect with the river bottom or the opposite shore (id.; Exh. HO-E-24).[126]

126/ The mixing zone is that portion of the discharge plume in which the temperature increase over pre-existing ambient conditions would be four degrees F or less (Exh. HO-E-24).

The Company presented an analysis of the impact of the proposed intake and discharge on aquatic species from the standpoint of susceptibility to entrainment and impingement, as well as thermal stress (Exh. BE-6, pp. 7-13 to 7-14).[127] Based on the expected limits of the mixing zone, the Company stated the discharge plume would not present a thermal barrier to movement of aquatic organisms in the river (id.). However, the Company's analysis indicated that impingement would cause annual mortality losses of from .97 percent to 4.72 percent of the population of impacted aquatic species (Exh. BE-59, pp. 6.2-2 to 6.2-3).[128] The Company noted, however, that the balance of the population of fish and shellfish indigenous to the Weymouth Fore River would be maintained (Exhs. BE-6, Sec. 7, pp. 13-14, HO-RR-78). The Company further indicated that, as part of the water quality certification process under the U.S. EPA, a technical advisory committee had been formed to review the Company's plans for mitigation of impacts on aquatic species (Tr. 50, p. 40; Exh. BE-59A).

Finally, the Company reported that the Edgar site is primarily classified under Federal Emergency Management Agency ("FEMA") regulations as an "Area of Minimal Flooding"; in addition, FEMA has classified a small section abutting the Weymouth Fore River as a zone of "Special Flood Hazard" (Exhs.

127/ Susceptibility to entrainment or impingement for a specific aquatic species is dependent on such factors as its thermal tolerance and natural avoidance of thermal plumes, as well as on individuals' ability to survive if drawn into the facility intake and caught against protective screening.

128/ The higher figure is the percent impingement of spawning smelt population in the Weymouth Fore River, while the lower percentage provides the same information for the cunner population (Exh. BE-59, pp. 6.2-2, 6.2-3). The figure for spawning smelt represents .38 percent of the annual New England catch (id.). Species studied by the Company include alewife, Atlantic menhaden, rainbow smelt, silver hake, Atlantic tomcod, Atlantic silverside, cunner, windowpane, winter flounder, lobster, and soft-shell clams (id.).

HO-E-30, BE-59, Fig. 5.9-2). The Company noted that the flood hazard to the portion of the primary site within the floodplain would be mitigated via the construction of a new bulkhead and the use of riprap (Exh. HO-E-30).

(2) Analysis

With respect to surface water quality, the record indicates that generating facility waste treatment systems could be designed at the primary site to ensure that river water quality standards would not be violated. Effluent would be subject to NPDES permit limitations and EPA criteria for discharges into receiving waters. Safeguards would be incorporated into the design of the facility to prevent inadvertent release of pollutants from the proposed facility into the Weymouth Fore River. The record further demonstrates that dredging would not adversely affect water quality beyond a local temporary increase in turbidity.

With respect to aquatic ecology, the record shows that impingement could cause mortality losses of from .97 percent to 4.72 percent of the population of impacted aquatic species. Use of state-of-the-art design in accordance with requirements of the technical advisory committee, however, would ensure that this loss is minimized and that long term population could be sustained without imbalance to the population of fish and shellfish indigenous to the Weymouth Fore River. In addition, the discharge plume would not create a thermal barrier to migration. Further, while there may be temporary displacement of shellfish beds, the Company has shown that it would take measures to mitigate such impacts.

With respect to wetlands, the record indicates that the greatest disturbance to wetland-designated areas would occur along the route of Algonquin's natural gas pipeline, but that such impacts would be temporary.[129]

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to surface water quality and wetlands, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to water resources and wetlands.

The Siting Board expects that the Company will take all measures to ensure minimum impacts on surface water quality and aquatic ecology, including attention to protection of fisheries from impingement and entrainment, to inadvertent contamination of receiving waters, and to mitigation of impacts to shellfishing beds as required by the EPA. The Siting Board notes that the required FERC review of Algonquin's natural gas pipeline should provide for restoration of wetlands temporarily disturbed and mitigation for any damage to wetlands, as well as consideration of measures to minimize impacts of the Weymouth Fore River crossings.

The record demonstrates that the Company's construction plans with implementation of the aforementioned mitigation measures, as well as FERC's review of Algonquin's proposed natural gas pipeline, adequately ensure a minimum impact on the environment with respect to surface water quality and wetlands.

Accordingly, based on the foregoing, the Siting Board finds that with the implementation of the above mitigation, the environmental impacts of the proposed facility at the primary site would be minimized with respect to surface water quality and wetlands.

129/ The Siting Board does not have jurisdiction over impacts of Algonquin's natural gas pipeline. Such impacts will be reviewed by FERC in accordance with all applicable regulations.

c. Land Resources

BECo stated that the overall primary site consists of approximately 56 acres, of which 5.3 acres would be used for the proposed facility (Exhs. BE-6, p. 2-1, BE-59, p. 6.85-1, Table 6.5-1).[130] The Company asserted that the primary site is already industrialized and that no tree clearing would be required (Exh. BE-6, p. 2-1).

The Company indicated that the proposed facility would be interconnected via three underground transmission lines to an existing substation within the primary site, and that there would be no need for off-site transmission improvements (Exh. HO-E-63). BECo further stated that the cooling water intake and wastewater discharge would occur on-site, without the need for off-site access, and that process water would be obtained from the City of Quincy via an existing pipe under the Weymouth Fore River (Exh. BE-6, pp. 2-2, 2-7; Exh. BE-120).

The Company stated that a 10.7-mile, 24-inch gas pipeline lateral had been proposed to supply natural gas for the proposed facility (id, p. 2-8; Exh. HO-E-103).[131] BECo indicated that the pipeline, proposed by Algonquin to serve the proposed facility, would traverse approximately 35 acres of land along a

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130/ BECo indicated that although 5.3 acres would be dedicated for the proposed facility, approximately 25 acres of additional land would be utilized for construction laydown, construction parking, access and internal roadways (Exh. BE-59, p. 6.5-1, Table 6.5-1).

131/ The Company provided information stating that the last action FERC took on this docket was to require preparation of a Federal Environmental Assessment ("EA"); as of August, 1992, the EA has not been prepared (Exh. WAT-30). The Siting Board notes that subsequent to the close of the record it received a FERC notice indicating that Algonquin had withdrawn its application to construct the 10.7-mile Edgar Lateral. The Hearing Officer takes administrative notice of this notice pursuant to 980 CMR. 1.04(5). Algonquin stated that since specific timing for the Edgar project is indefinite, it will refile the application when the timing of the project is more definite.

route originating in Avon, Massachusetts and extending through the neighboring Massachusetts towns of Randolph and Braintree and across the Weymouth Fore River to the primary site (Exh. HO-E-102, p. 3, Table G-2; Tr. 56, p. 131).[132]

BECo provided information indicating that the proposed pipeline route would largely parallel existing transmission lines and active and abandoned rail lines, and also extend along new right-of-way ("ROW") including segments passing through the Braintree Town Forest and a section of the Cranberry Brook Area of Critical Environmental Concern ("ACEC") in Braintree (Exh. HO-RR-102; Tr. 56, p. 127). The Company noted that the section of the ACEC traversed by the route includes streets and residences that were built up prior to the area's designation as an ACEC (Tr. 56, p. 127).

BECo's witness, Dr. Morgenstern, testified that, according to Algonquin's FERC filing, Algonquin would clear trees within the Braintree Town Forest to create a new pipeline ROW approximately 50 feet wide with an additional 25 feet of temporary workspace (id., pp. 131-132; Exh. HO-E-103, Attachment A). Dr. Morgenstern added that this ROW would be kept clear of trees thereafter, but that the bordering edges would be allowed to revegetate to a grassed-over condition which would be favorable to wildlife habitat in the area (id.).

BECo indicated that a total of 20 acres of forestland along the entire length of the proposed pipeline route would be cleared, and that 3.1 acres of this total would be allowed to revert to forest after construction is completed (Exh. HO-E-102, Resource Report 3, p. 10; Tr. 56, p. 135).

BECo also provided the Siting Board with information on an alternative pipeline route identified by Algonquin which would avoid crossing the center of the Braintree Town Forest, as well

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132/ BECo stated that the pipeline route proposed by Algonquin would permanently affect 29 acres of land, and temporarily affect 6 acres of land (Exh. HO-E-102, Table G-2).

as additional route variations suggested during the FERC review process (Exh. EBCA-RR-4; EBCA-RR-7).[133] Noting that Algonquin's alternative route would have greater impacts than the proposed route on sensitive portions of the Cranberry Pond ACEC, Dr. Morgenstern indicated that, in her professional opinion, it would be preferable to avoid such areas in routing the pipeline (Tr. 56, pp. 129-130).

The record demonstrates that the proposed facility would utilize an already cleared site currently used for utility purposes, and would require no new or expanded ROW for transmission, water supply or wastewater discharge purposes. Although a new 10.7-mile long pipeline would be required to supply natural gas, Algonquin's proposed route would largely follow existing ROWs limiting permanent loss of forest to 17 acres. Additionally, a range of alternative routes in the vicinity of the Braintree Town Forest and Cranberry Brook ACEC has been developed as part of FERC's review of the proposed pipeline. FERC has primary responsibility to address siting of the pipeline, and the scope of its review to date provides assurances that issues of forest clearing and routing through sensitive areas will be addressed in detail.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to land resources, including information on FERC's review to date of

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133/ The original Algonquin filing with FERC was updated to reflect additional alternative routes submitted by Algonquin, the Town of Braintree and FERC (Exh. EBCA RR-7). As of October 30, 1991, new documentation filed with FERC reflected eight different routes and route variations: the original preferred Algonquin route, an alternative Algonquin route, three Town of Braintree route variations, and three FERC route variations (id.). The routes vary from 11,175 feet to 14,950 feet in length (id.). Although the alternative routes include variations to avoid portions of the Braintree Town Forest and Cranberry Brook in Braintree, four of the route variations would require the pipeline to be located along town streets for a considerable length (id.).

Algonquin's proposed natural gas pipeline, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to land resources.

The record demonstrates that the Company's construction plans, as well as FERC's review of Algonquin's proposed natural gas pipeline adequately ensure a minimum impact on the environment with respect to land resources.

Accordingly, the Siting Board finds that environmental impacts of the proposed facility at the primary site would be minimized with respect to land resources.

d. Noise

(1) Description

BECo stated that the proposed facility would not generate adverse noise impacts at the nearest residential receptors (Exh. BE-59, p. 2.4-5). BECo also stated that operation of the proposed facility would meet MDEP noise criteria requiring that noise levels not be increased by more than 10 decibels above ambient levels at the site boundaries and the nearest residences (Exh. BE-6, p. 7-19).[134] The Company asserted that the predicted noise levels at the nearest residential receptors would fall below recommended EPA guidelines for avoiding indoor activity interference and annoyance (BECo Initial Brief, p. 241). Finally, the Company stated that the noise impacts of continuous construction activities are expected to be minimal (Exh. BE-59, p. 6.4-2).

The Company delineated five sources that would contribute to increases in noise during operation of the facility: (1) combustion turbine engine noise at the HRSG stacks;

134/ BECo indicated that it will comply with Weymouth's noise regulations as well as with state and federal regulations (Tr. 58, p. 78). However, the Company asserted that the regulations of the City of Quincy are not applicable with respect to noise or any other aspect of the proposed facility (id.).

(2) combustion turbine engine noise at the air intake filter house; (3) noise from the 125 MVA main power transformer; (4) combustion turbine engine noise emanating through the walls of the turbine building; and (5) interior noise of the HRSG and peripherals emanating through the walls of the HRSG building (Exh. BE-6, p. 7-18). BECO stated that the transformers would be the most significant noise contributor to the overall facility noise level at the nearest residence and property line (Tr. 54, p. 126).

With respect to existing background noise, the Company claimed that the primary noise influences at the site are man-made sources related to the urban, commercial/industrial nature of the surrounding area (Exh. BE-59, p. 5.5-1). BECo identified the predominant existing noise source in the site area traffic on route to and from Logan Airport and operation of the nearby Proctor and Gamble facility contribute to the existing noise levels of the area (Exh. BE-59, p. 5.5-1).

The Company selected four representative locations at which to conduct baseline ambient noise measurements (id.). The four locations are as follows: (1) the existing main access drive to the primary site, located on the south side of Bridge Street; (2) the east property line of the primary site abutting Monatiquot Street ("east property line"); (3) Taffrail Road, adjacent to the shoreline of Town River Bay, across the Weymouth Fore River, in the residential community of Germantown in Quincy; and (4) Venus Road, at the intersection of Glenrose Street across the Weymouth Fore River in East Braintree (id., p. 5.5-2).[135] The nearest residence is located 985 feet away from the center of the proposed facility, on Monatiquot Street (id., p. 6.4-2; Tr. 54, p. 143).

135/ In addition to the east property line, Taffrail Road and Venus Road are considered residential receptors. The existing main access drive to the primary site is representative of a property line location only.

For each of the four receptors, BECo conducted ambient noise measurements for the summer and winter, during weekdays and weekends, broken down by day and night (Exh. BE-59, Tables 5.5-1 and 5.5-2).[136] The Company indicated that existing weekday daytime L_{90} noise levels at the nearest residence range from 46 to 55 decibels (HO-RR-57A, p. N-1-4).

With the operation of the proposed facility, BECo stated that assuming a continuous noise contribution from the facility both day and night, the L_{dn} noise level would be 59 decibels (Exh. HO-E-58). The Company asserted that the EPA Levels Document recommends a L_{dn} level of no more than 60 decibels, based on 45 decibels for outdoor activity interference with a 15 decibel reduction for exterior wall construction for open windows (id.).[137]

The Company developed estimates of future operational noise levels for all of the measurement periods at the three residential receptors -- east property line, Taffrail Road, and Venus Road (Exhs. HO-E-59, HO-E-93).[138] The highest absolute

136/ There are different methods to measure ambient sound levels -- L_{90} are those sound levels that are exceeded 90 percent of the time and L_{10} are those sound levels that are exceeded 10 percent of the time (Exh. BE-59, p. 5.5-2). L_{90} is used as the MDEP criterion (id.). The L_{dn} indicator, used in certain EPA noise guidelines, is the day-night equivalent sound level that reflects an average of periodic noise readings over a 24-hour period, with a 10 decibel correction factor added to the readings during normally quiet late-night hours (Exh. WAT-42, p. 9).

137/ WATER provided a copy of the Levels Document which indicated that the EPA outdoor level guideline is an L_{dn} of 55 decibels, based on the fact that outdoor noise levels should be no greater than 60 decibels, with a 5 decibel margin of safety (Exh. WAT-42, p. 20).

138/ BECo stated that although it did not specifically determine the predicted noise increase at the existing main access road to the primary site, it anticipated that the increase would be less than that on the east property line due to the increased distance and higher level of ambient noise at the existing access road (Exh. HO-E-94).

noise increase is predicted to be 7.8 decibels at Monatiquot Street, on a winter, weekend night (id.)[139] The noise levels on Taffrail Road are expected to be the same with and without the facility, while the highest predicted increase for Venus Road is 7.0 decibels on a winter, weekend night (id.). BECo indicated that the operation of the proposed facility would result in a day-night noise increase at the receptors (Exh. HO-E-95). However, BECo stated that although the EPA 55 decibel L_{dn} guideline would be exceeded, the existing noise levels at the receptors already exceed 55 decibels, and that all of the increases are below the MDEP 10 decibel guideline (id.).

BECo stated that construction of the facility would be phased over two years and that the maximum construction noise would occur during pile driving, site excavation and grading (Exhs. BE-59, p. 6.4-2, HO-E-29). BECo stated that pile driving, required for generating unit foundations and bulkheading, would last approximately four months, and site excavation and grading would last approximately two months within the four-month pile driving period (id.). The Company acknowledged that pile driving would create an annoying environment for the residential neighborhood adjacent to the east property line as well as for the homes located along Venus Road (Exh. BE-59, p. 2.4-5).[140]

The Company projected that the construction noise level at the east property line, would be an L_{10} level of 67 decibels and an average noise level of 63 decibels (Exh. BE-59, p. 6-4.2)[141]

139/ The Company indicated that the highest future ambient noise level at the east property line would be 57.4 dBA occurring during a weekend day (HO-RR-57A, p. N-1-4).

140/ The Company stated that pile driving for wharf maintenance also would create an annoyance for residents on the east side of Kings Cove and across the Weymouth Fore River in Quincy (Exh. BE-59, p. 2.4-5).

141/ BECo indicated that UE&C developed the construction noise assessments based on experience with similar electric generating facilities (Exh. HO-E-28). UE&C used the following three electric generating facilities as a basis for estimating

The Company stated that based on the existing average noise levels, there would be an increase of 8 to 10 decibels during construction (id.). BECo indicated that construction work would generally be scheduled during the hours of 6:30 a.m. to 3:45 p.m., to minimize possible noise impact concerns (id.; Tr. 54, pp. 37, 138).[142] However, the Company indicated that it would be necessary to carry out limited nighttime pouring of concrete for structural integrity (id.). Further, BECo indicated that it has agreed not to engage in construction activities at the primary site on Sundays (Tr. 58, p. 73).[143]

The Company also provided information concerning intermittent noise emissions which are associated with start-up activities -- consisting of steam blowing[144] to clean the pipes and un-scheduled safety valve releases (Tr. 56, p. 56). BECo stated that both activities would be of limited duration (id.).[145] However, the Company acknowledged that the intermittent noise activities would be louder than construction

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construction noise: Hoosier Electric Membership Cooperatives Meron Station (two 490 MW units); Somerset Unit No. 1 (one 625 MW unit); and Seabrook Nuclear Generating Station (two 1,100 MW units) (Exh. HO-E-28).

142/ Mr. Schmidt indicated that it may be possible for BECo to schedule construction so that noisier construction tasks would not begin until 8:00 a.m., if so required by Weymouth (Tr. 54, pp. 139-140).

143/ The Company indicated that if Weymouth imposed a requirement prohibiting construction on Saturdays, it would comply with this requirement (Tr. 58, p. 73).

144/ The pipes would be steam blown in order to clean them out prior to start-up of the facility. (Tr. 56, p. 56).

145/ Mr. Schmidt stated that a safety-valve release, which could occur during operation of the facility, could last up to ten minutes (Tr. 54, p. 130).

noise and that the increase would exceed 20 decibels (id., pp. 56, 57).[146]

BECo stated that the proposed facility would incorporate noise mitigation through the use of the following equipment and design features: (1) barrier walls for the main power transformers; (2) sound attenuators for the combustion turbine intakes; (3) exterior sound walls for the turbine and HRSG buildings; and (4) a landscaped "green belt" located along the east property line of the primary site (Exh. BE-59, p. 7.4-1). BECo indicated that the construction of barrier walls at each of the three step-up transformers at the primary site would provide an anticipated sound level reduction of three decibels at each of the receptors (Exh. HO-E-96).[147] BECo also indicated that the landscaped greenbelt also would provide three decibels of noise mitigation at the east property line (id.). The Company stated that the transformer barriers and landscaped greenbelt were not represented in the estimates of facility noise impacts (id.).

Weymouth requested that the Siting Board include a number of conditions addressing construction noise and operational noise (Weymouth Site Banking Brief, p. 10). Weymouth requested that the Siting Board require BECo to (1) prevent the idling of

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146/ Weymouth's Code states that noise increases more than 20 decibels over ambient background are considered a nuisance and are subject to ticketing or criminal prosecution (Exh. WAT-41). In response to a request by the Siting Board staff, BECo inquired as to the interpretation by Weymouth regarding the applicability of the Code to different types of noise -- operating, construction and intermittent (Exh. HO-RR-111). The WBH indicated that no documented policies regarding the enforcement of the Code exist, but noted that the intent of the by-law is to encompass all types of noise, with no indication that various types of noises would be treated differently (Exh. HO-RR-111S).

147/ BECo noted that the placement of localized barrier walls at each of the proposed transformers would be more effective than the placement of a single barrier for the purpose of providing blanket coverage for both the proposed and existing transformers (Exh. HO-RR-103).

inactive construction equipment at the project site; (2) minimize noise levels before 8:00 a.m.; and (3) limit primary construction activity to between the hours of 6:30 a.m. and 4:45 p.m. except as necessary for structural integrity or safety reasons (id.). Finally, with respect to possible noise citations issued by the WBH, Weymouth requested that BECo be required to respond promptly to any such noise citation, and, if necessary, include appropriate noise mitigation measures, such as temporary sound barriers (id.). Weymouth noted that this requirement would ensure that BECo install effective noise mitigation features as proposed, including barrier walls for the main power transformers, sound attenuators for the combustion turbine air intakes, exterior walls that adhere to minimum sound transmission ratings at turbine and HRSG buildings, and a green belt area to be located along the east property line (id., pp. 10 and 11).

(2) Analysis

In past decisions, the Siting Board has reviewed estimated noise impacts of proposed facilities for general consistency with applicable government regulations, including the MDEP's 10 decibel guideline. Enron, 23 DOMSC at 210; EEC, 22 DOMSC at 375; West Lynn, 22 DOMSC at 100; MASSPOWER, 20 DOMSC at 85; Altresco-Pittsfield, 17 DOMSC at 401. In addition, the Siting Board has considered the significance of expected noise increases 2which, although lower than 10 decibels, may adversely affect existing residences or other sensitive receptors such as schools. EEC, 22 DOMSC at 375; Altresco-Pittsfield, 17 DOMSC at 401; NEA, 16 DOMSC at 402-403.

In this case, the Company has conducted noise analyses for the primary site, encompassing both operational and construction noise levels. BECo asserted that the facility would have no adverse noise impacts at the nearest residential receptors, based on adherence to the MDEP 10 decibel increase criteria. However, the 7.8 decibel increase at the east property line, resulting from operation of the proposed facility, is high in comparison to the residential receptor increases noted in recent reviews of proposed generating facilities. Enron, 23 DOMSC at 210; West Lynn, 22 DOMSC at 100; MASSPOWER, 20 DOMSC at 389. In addition, the estimated future ambient levels are above those in most previous reviews.[148] However the inclusion of barrier walls at the transformers would provide additional mitigation of three decibels, therefore the total increase with the stated mitigation would be 4.8 decibels.[149]

The Company conducted ambient noise measurements at four receptor points -- three residential points and one at the existing main access drive to the site. However, the second phase of the analysis, which consists of estimating the increases at the receptors due to the operation of the proposed facility, and forms the basis of adherence to MDEP noise criteria, did not include a measurement at the existing main access road to the site. Although BECo provided a rationale for not conducting this measurement, the Siting Board notes that the MDEP guidelines encompass both residential and property line receptors. In addition, it should be noted that the ambient noise measurements at the existing main access drive to the site are quite high, ranging from 46 to 66 decibels in the summer and 52 to 70 decibels in the winter (See Exh. BE-59, Table 5.5-2).

Further, the Siting Board notes that the day-night noise level of 59 decibels, representing the maximum operational noise contribution from the facility, exceeds the EPA outdoor guideline

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148/ The Enron facility was expected to result in a maximum ambient noise level of 52 dBA; however, the highest noise increase at a residence from operation of that facility was to be 4.8 decibels, based on noise modeling, and 4.0 decibels based on terms of a local zoning approval. Enron, DOMSC 23 at 207-208.

149/ The Siting Board notes that the Company also did not include the landscaped buffer in its calculation. Moreover, it is unclear whether the estimated decibel decrease would occur throughout the year, including defoliate conditions. Further, the Company did not assert any cumulative reduction resulting from the barrier walls and the landscaped buffer.

of 55 decibels. The EPA Levels Document provides that the outdoor level guideline is 55 decibels, based on the fact that outdoor noise levels should be no greater than 60 decibels with a five decibel margin of safety. BECo's assertion that the guideline is 60 decibels did not take into account the five decibel safety margin under consideration.

The Siting Board notes that the assertion by the Company that it is acceptable to be above the 55 decibel level as long as the facility does not push the receptor over the guideline, since the ambient measurement is already over 55 decibels, does not fully address our concerns. Rather, the Siting Board is particularly concerned with holding the noise increase down if the existing level is already above the 55 decibel guideline.

Finally, although construction noise levels were estimated, they were not presented in a format to ascertain the increase in decibels from ambient to construction operation noise levels. BECo's analysis of different indicators, including the L_{10} and average noise estimates in the 65 decibel range for the east property line during construction, provides limited insight as to whether the construction noise levels are minimized.[150]

Therefore, in order for impacts to community noise levels to be minimized at the primary site, BECo must meet the following conditions: (1) BECo shall incorporate all proposed mitigation techniques as described herein so that the continuous noise increase from the operation of the proposed facility is no more than five decibels; (2) BECo shall refrain from conducting construction that generates significant noise before 8:00 am; and (3) BECo shall confine all primary construction activity to between the hours of 6:30 a.m. and 4:45 p.m. Monday through Saturday, except as necessary for structural intergrity or safety reasons; and (4) if issued a noise citation by the Weymouth Board

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150/ Although the MDEP standard does not apply to construction noise, a potential 20 decibel increase from construction noise may violate Weymouth's local standard.

of Health or MDEP, BECo shall promptly investigate the potential source of cited noise and, as necessary, provide temporary sound barriers or implement other appropriate measures to mitigate such noise.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to noise impacts, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to noise impacts.

The record demonstrates that the Company's construction plans with implementation of the aforementioned conditions, adequately ensure a minimum impact on the environment with respect to noise impacts.

Accordingly, based on the foregoing, the Siting Board finds that with implementation of the aforementioned conditions, the environmental impacts of the proposed facility at the primary site would be minimized with respect to noise impacts.

e. Water Supply

(1) Description

The Company stated that it expects to pursue use of potable water from the City of Quincy as its preferred water supply for the proposed facility at the primary site ("proposed water supply plan") (Exh. BE-120, p. ii).[151] The Company stated that the City of Quincy obtains water from the Massachusetts Water

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151/ BECo indicated that, initially, it had anticipated purchasing potable water from the Weymouth water system to operate the proposed facility, which would require expansion of the Weymouth water system to allow such supply ("Weymouth supply") (Exh. BE-120, p. i). The Company stated that, based on MDEP's rejection of Weymouth's application for an increased water withdrawal permit under the Water Management Act, M.G.L. c. 21G, it no longer considers the Weymouth supply to be a preferred option (id.).

Resources Authority ("MWRA"), and that the MWRA would need to further review the eligibility and any related requirements for the Company to utilize the City of Quincy water supply (id.).[152] The Company stated that, should its proposed water supply plan prove not to be feasible based on further review, it would utilize a backup water supply involving barge transshipment of treated process water from the Company's New Boston station in South Boston to the primary site ("backup water supply plan") (id.).

In order to develop its proposed and backup water supply plans, the Company stated that it identified and evaluated 12 water supply options, including various potable water sources, industrial sources, on-site sources and off-site non-potable sources (Exh. BE-120, p. i). The Company stated that it selected four preferred options based on technical screening criteria (id., p. ii).[153, 154] In addition, the Company stated that it identified three water use reduction measures which could be implemented as part of the water supply plan for the proposed facility, including (1) use of dry combustors for NOx control,

152/ The MWRA has developed a report entitled "Policy and Procedures for MWRA Water Connections Serving Property Partially Located in a Non-MWRA Community," (Exh. HO-E-101, Attachment). The report indicated that one of the criteria for approving a water connection application is whether water may be supplied to the project without jeopardizing MWRA water supplies or the ability of MWRA to meet the legitimate water supply needs of existing MWRA user communities, including those with local sources (id., p. 6).

153/ In addition to the proposed and backup water supply plans, the preferred options included two additional options: (1) use of MWRA wastewater with on-site treatment; and (2) on-site desalinization of water from the Weymouth Fore River (Exh. BE-120, p. i).

154/ The criteria included (1) the level of technical feasibility, (2) the quantity of available water, and (3) the complexity of required delivery improvements (Exh. BE-120, p. ii).

(2) collection and treatment of on-site process wastewater, and (3) collection and reuse of on-site stormwater runoff (id.).

BECo indicated that it then performed further conceptual design development and detailed economic evaluation of its four preferred water supply options and three identified water use reduction measures (id.).[155] Based on its detailed analysis, the Company (1) determined that it could reasonably implement water use reduction of 215,000 gpd through incorporation of on-site stormwater reuse and use of dry combustor technology with power augmentation,[156, 157] and (2) selected its proposed and backup water supply plans (id.).

The Company indicated that it based its evaluation and selection of water supply plans on a facility water requirement of approximately 385,000 gpd, assuming the above water use reduction measures and facility operation based on (1) a 100 percent capacity factor, and (2) gas-fired generation for 320 days and oil-fired generation for 45 days with use of SCR

155/ The Company also included the Town of Weymouth supply as a fifth supply option in its detailed analysis (Exh. BE-120, pp. ii, 4-8). See n. 153, above.

156/ BECo stated that use of on-site stormwater reuse as part of its water supply would reduce the facility's average water requirements by 80,600 gpd (Exh. BE-120, p. 1-4). The Company also indicated that, while an MDEP determination as to facility design measures required to comply with air quality requirements is pending, the dry combustor technology would avoid use of steam injection to meet NOx emissions limitations and, in the case of the base dry combustor design, thereby further reduce water requirements by 135,000 gpd (id.; Exh. HO-RR-93S, Table 5).

157/ The Company indicated that, while the dry combustor technology would provide a nominal water savings of approximately 491,000 gpd at a 100 percent capacity factor, the power output of the facility would be reduced by 22 MW (Exh. BE-120, p. 2-2). The Company further indicated that power augmentation could be incorporated to offset the power output loss, but that power augmentation requires steam injection and, therefore, under the Company's base dry combustor design, net water savings would be reduced to 135,000 gpd (id.).

(Exh. BE-120).[158] In addition, as part of its revised air quality analysis, BECo estimated facility water requirements for eight alternative design options ranging from 44,600 gpd to 654,300 gpd, assuming in all cases a 100 percent capacity factor and incorporation of on-site stormwater reuse (Exh. HO-RR-93S, Table 5).[159]

In justifying its selection of the proposed water supply plan, the Company stated that its analysis demonstrated that the City of Quincy supply, in addition to being the most economic[160] and reliable water supply source, would pose the least environmental impact to the proposed site vicinity (id.,

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158/ The 385,000 gpd water requirement is consistent with the Company's proposal as presented in this proceeding. In its recent BACT submission to MDEP, however, the Company recommended that the BACT determination should be based on one of two design options either of which would involve larger water requirements, as follows: (1) an option requiring 654,300 gpd, assuming two 100 MW dry combustors, power augmentation with steam injection, and operation based on 365 days of gas-fired generation without SCR; and (2) an option requiring 650,900 gpd, assuming two 100 MW dry combustors, power augmentation with steam injection, and operation based on 320 days of gas-fired generation and 45 days of oil-fired generation with steam injection and SCR for NOx control (Exh. HO-RR-93S, Table 5) (see Section II.D.1.a.(1)(a), above).

159/ The Company presented three design options involving the minimum water requirement of 44,600 gpd: (1) an option assuming two 100 MW dry combustors and facility operation based on 365 days of gas-fired generation without SCR; (2) an option assuming two 110 MW dry combustors and facility operation based on 365 days of gas-fired generation with SCR; and (3) an option assuming two 110 MW combustors and facility operation based on 320 days of gas-fired generation and 45 days of oil-fired generation with SCR (Exh. HO-RR-93S, Table 5). However, the Company indicated that the above options, which utilize dry combustor technology without power augmentation, would provide net power output levels approximately 22 MW to 38 MW below that of options utilizing two 110 MW conventional combustors (id., Table 4).

160/ The Company estimated a 1994 present value cost of $18,838,000 for the proposed water supply plan (see Section II.D.2., below).

p. ii). The Company stated that it would use an existing Company-owned tunnel, which passes under the Weymouth Fore River between Weymouth and Quincy, to connect the proposed facility to the Quincy water system (id., p. 3-2). The Company added that limited improvements to the Quincy water system would be necessary to serve the proposed facility (Tr. 55, pp. 143-145). The Company indicated that its other identified supply options would involve additional on-site or off-site facilities and associated environmental impacts, as compared to the proposed water supply plan (Exh. BE-120, pp. 3-3 to 3-11).[161]

With respect to the dependence of BECO's proposed and backup water supply plans on the MWRA system, the Company stated that the MWRA has a safe yield supply capability of 300 million gallons per day ("mgd") as compared to a current systemwide demand of 279 mgd (Exh. HO-E-89). The Company provided a copy of the 1990 report "MWRA Long Range Water Supply Program" ("LRWSP"), and based on the LRWSP, stated that the MWRA expects its existing supply resources to be adequate until at least the year 2000 and possibly until as late as 2020 (id.).[162] The Company stated that, to help ensure long-term supply adequacy, the LRWSP includes programs to maximize water conservation, both through

161/ The Company noted that the installation of additional on-site treatment facilities would be required under the desalinization option and the MWRA wastewater reuse option, and the development, expansion or refurbishment of water supply sources in the surrounding area would be required under options involving new private wells, purchase of water from Weymouth, and utilization of the Quincy Reservoir (Exh. BE-120, pp. 3-3 to 3-11).

162/ The Company noted that the LRWSP recognizes two significant sources of uncertainty in assessing future supply adequacy: (1) the uncertain long term effectiveness of water conservation efforts; and (2) the potential for added demands on systemwide supplies as a result of possible contamination or other loss of local water supplies in a number of communities, including not only partial-user MWRA communities but also non-MWRA communities that are contiguous to the MWRA service territory (Exh. HO-E-89).

reduction of existing demand and minimization of future demand, as well as programs to comprehensively protect existing local water supplies in 40 identified member and non-member communities (id.).

To address possible future supply shortfalls, the Company stated that the LRWSP identifies numerous supply options ranging from the enhancement of existing supply resources and the development of new local sources to the development of major new system sources such as diversion of the Connecticut River, Merrimack River or Millers River (Exh. HO-E-90). Despite the inclusion of major new source options in the LRWSP, however, the Company's witness, Mr. Schmidt, maintained that there is a possibility that the MWRA will not need to develop any such sources (Tr. 56, p. 23). Mr. Schmidt further stated that, given the current MWRA surplus of approximately 20 mgd, the addition of the Company's proposed 385,000 gpd water requirement to the MWRA system demand would not be a significant factor in increasing the likelihood that the MWRA would require such a major new source (id., p. 27).[163]

With respect to mitigating any impact of its water requirement on the Quincy water system and the MWRA, the Company stressed the proposed water conservation measures included in its facility design, which would save 215,000 gpd (Exh. BE-120, p. 1-4). BECo stated that, as part of complying with the Quincy water system's connection requirements, and any MWRA requirements for service to customers in non-member communities, it expects to further support water conservation by contributing between $40,000 and $50,000 for leak detection programs in Quincy (Tr. 56, pp. 14-15). As an additional offsetting consideration,

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163/ The Company did not address the potential impact on the MWRA system of a water requirement of approximately 650,000 gpd, consistent with recommendations in the Company's revised BACT analysis (see n. 158, above). However, the current 20 mgd surplus would allow the MWRA to meet this higher requirement, as well, without an immediate need for a system expansion.

the Company noted that the MWRA revenues resulting from its proposed water purchase would be particularly beneficial to the MWRA in the upcoming several years, given the MWRA's relatively extensive capital improvement schedule and associated expectations for upward pressure on water rates (Tr. 55, pp. 135-136).

With respect to the backup water supply plan, BECo indicated that the logistical difficulty of delivering water to South Boston -- the transfer point for barge transshipment -- would be essentially equal to that of delivering water directly to the Edgar site under the proposed water supply plan (id., pp. 139-146). Specifically, the Company stated that the impacts of the two water supply plans on the MWRA and on local water systems -- the Quincy system under the proposed water supply plan or the City of Boston system under the backup water supply plan -- would be comparable (id., p. 146). BECo did not identify or evaluate any specific environmental impacts of barge transshipment itself, under the backup water supply plan.[164]

WATER and the Attorney General argue that MWRA approval of the proposed water supply plan is by no means assured (WATER Site Banking Reply Brief, pp. 9-10; AG Site Banking Brief, pp. 11-12). The Attorney General argues that the backup water supply plan may also require MWRA approval, and that in any event the consistency of such a water supply with applicable water service policies would become unclear after the retirement of BECo's New Boston facility (AG Site Banking Brief, p. 12). Weymouth states that the Company is not seeking Siting Board approval of any water supply alternatives other than the proposed and backup water supply plans, and therefore, argues that the Siting Board should not approve, conditionally or otherwise, any alternative other

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164/ The Company stated that the principal difference between the proposed and backup water supply plans is the added cost of barge transshipment, and further stated that there would be no environmental benefits of barge transshipment which might offset the added cost (Tr. 56, pp. 7-8).

than the proposed or backup water supply plans as part of the site-banking review (Weymouth Site Banking Brief, p. 3).

(2) Analysis

In the past, the Siting Council has reviewed two proposed generating facilities in recent years that would rely on a public potable water supply for significant portions of process water requirements,[165] but reviewed no such proposal involving an MWRA water supply. The MWRA's LRWSP shows the complexity of assessing the long term adequacy of the MWRA's supply resources, and recognizes the likelihood that new or expanded supply resources with associated costs and environmental impacts may be needed beginning sometime between 2000 and 2020.

In addition, as argued by intervenors, the Company has not established that it has an implementable water supply plan fully in place. The Company acknowledges that additional review is required for its proposed water supply plan. Although insisting that barge transshipment meets all water service requirements, the Company has not pointed to any evidence of such a water use in the past, nor provided any written agreement or opinion from the City of Boston water system or the MWRA to confirm that the backup water supply plan can be implemented.

With respect to water use reduction, the Company has indicated its willingness to incorporate on-site stormwater reuse and use of dry combustor technology to reduce water requirements by an estimated 215,000 gpd. However, the Company's air quality analysis identifies design options which would allow the Company to reduce water requirements below the level assumed in its water supply analysis by an additional 351,000 gpd, resulting in a facility water requirement of less than 100,000 gpd.

165/ The Altresco-Pittsfield facility and the Eastern Energy facility were expected to use approximately 700,000 gpd and 165,000 gpd, respectively, of potable public water supply. Altresco-Pittsfield, 17 DOMSC at 402-403; EEC, 22 DOMSC at 297-299.

The record also demonstrates that the MWRA appears to have a policy in place to ensure that service is not extended to users partly located in non-member communities if such service would jeopardize the long term integrity of MWRA supplies in meeting the needs of existing MWRA member communities and customers. In addition, the LRWSP, which has been included as part of the record and discussed at length by the Company, highlights the breadth of programs the MWRA has established to ensure the long term integrity of its water supply system.

The Company currently plans on contributing up to $50,000 for leak protection as a likely step to satisfy any MWRA requirements for a service extension to the proposed facility. In addition, as the Company points out, the expected revenue benefits to the MWRA of supplying the proposed facility may partly or fully offset any potential adverse impacts of such water service on the long term adequacy of MWRA supply resources.

Although the Company points to a possible contribution it might provide to the Quincy water system for leak protection, the Siting Board notes that there are numerous other program areas referenced in the LRWSP -- for example, local source protection and local source development -- which BECo might agree to support in addition to supporting leak protection programs, for purposes of obtaining a water service agreement to implement the proposed water supply plan consistent with MWRA policies. Given that there is at least some possibility of a need arising for development of new MWRA supply resources as early as 2000, it is appropriate that, if requested by the MWRA, BECo not only be prepared to support a variety of program areas as identified in the LRWSP, but be prepared to support such programs at levels capable of offsetting a meaningful portion of its proposed usage.

With regard to the backup water supply plan, the Company has failed to explicitly consider possible environmental impacts of barge transshipment, including such factors as air emissions from operating the barge and possible fuel storage and handling risks associated with fueling the barge. In addition, to the extent such environmental impacts should have been identified, the Company has failed to compare any such impacts with the environmental impacts of other water supply options identified in the Company's analysis but not selected as a backup water supply plan.

The Company has provided considerable analysis of possible water requirements under a range of combustor designs, and identified specific options for reducing water requirements. The Company also has addressed the likely impacts of its proposed water supply on the local area and on the City of Quincy and MWRA water systems. Finally, the Company considered a range of water supply options for meeting water requirements of the proposed facility at the primary site, and provided limited information on the impacts of the backup water supply plan and other water supply options.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to water supply, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to water supply. However, the Siting Board finds that, in the event the proposed water supply plan cannot be utilized, the Company did not provide sufficient information for the Siting Board to determine whether the environmental impacts of the proposed facility at the primary site, with implementation of the backup water supply plan, would be minimized with respect to water supply.

In terms of minimizing environmental impact, the Company has identified but not proposed facility design options capable of holding facility water requirements to less than 100,000 gpd under both the proposed and backup water supply plans.

Accordingly, based on the foregoing, 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 water supply.

f. Land Use

(1) Description

The Company stated that construction of the proposed facility at the primary site does not conflict with past use of the site (Exh. BE-59, p. 2.5-2). The Company indicated that the site topography is relatively flat, filled land, of which 0.5 acres is tideland (id.). The Company stated that the site, home to the retired Edgar Station, has been used for electric power generating purposes since the 1920's (id., p. 2.2-2). BECo listed the existing on-site features as a retired generating station, discharge canal, switchyard and switch house, transmission towers, fuel storage tanks, and two operating combustion turbine peaking units (id., p. 5.9-1).

The Company stated that Route 3A divides the site into north and south sections, whereby the north section is approximately 16 acres and the south section, where the proposed facility is to be located, consists of 40 acres (id., p. 5.6-1). BECo described the site as being completely bounded by the Weymouth Fore River to the north, south and west, with the east side bounded at the northern end by Kings Cove, at the center by Monatiquot Street and its adjacent residential area, and at the south end by Mill Cove (Exh. BE-6, p. 2-2). The Company stated that the nearest residences are located to the east on Monatiquot Street, approximately 1,000 feet from the facility (id., p. 7-21). BECo categorized the predominant land use of the area surrounding the site as densely populated (Exh. BE-59, p. 3.3-1). The Company characterized the areas in Braintree and Quincy, located directly across the Weymouth Fore River, as highly industrial, citing such facilities as the former General Dynamics Shipyard and the Braintree Electric Light Department's Potter Generating Station (Exh. BE-55, p. 7).

BECo stated that a green belt is proposed to be located along Monatiquot Street, consisting of a 60-foot wide buffer of deciduous and coniferous trees (Exh. HO-E-45; Tr. 54, p. 94). The Company also stated that it would develop the Kings Harbor Walk, an area located along the northeast portion of the site, by providing public access to the waterfront and outdoor recreation (Exh. HO-E-46).[166] The Company further indicated that this area is part of the Weymouth Waterfront Plan developed in 1988, and that BECo would be working in conjunction with the Waterfront Study Committee to maintain public access (Exh. BE-59, p. 5.9-2).

BECo indicated that under a Weymouth Zoning By-law, the site is located in a zone designated as General Industrial District I-2,[167] a zone which does not include electricity generation or public utility use (Exh. BE-59, p. 5.9-2).[168] BECo identified the area immediately to the east of the site as zoned for residential use -- Residential District R-1 (Exh. BE-55, p. 7). The Company stated that in addition to the above zoning issue, it appears that the facility would require a variance or exemption from building height requirements, as the proposed facility is 100 feet in height and the by-law height restriction is 80 feet (id., p. 8; BECo Initial Brief, p. 252).

With respect to transmission access, the Company reported it would need to construct a new natural gas pipeline to the site

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166/ The Weymouth/BECo Agreement provides for the construction, operation and maintenance of a waterfront park along King's Cove (Exh. WEY-21).

167/ Specifically permitted in the General Industrial District are such uses as dry cleaning, steam laundry, marinas, and broad categories such as assembly, manufacturing, and packaging (Exhs. Water-40, BE-59, p. 5.9-2).

168/ The Company stated that, pursuant to M.G.L. c. 40A, §3, it had previously applied for a request to the Department for a zoning exemption from Weymouth's zoning by-laws, however the request was withdrawn in May 1992 (Tr. 57, p. 34; Exh. WEY-37). BECo stated that it would refile for the zoning exemption when a new in-service date for the project is determined (Exh. WEY-37).

(See Section II.D.1.c, above) (Exh. BE-6, p. 5-22). However, BECo stated that it had not specifically evaluated the environmental impacts of any routing of the natural gas pipeline in terms of comparing the primary and alternative sites (Tr. 55, p. 86).[169] The Company further stated that it did not know the degree of residential impacts that would arise due to the placement of either the proposed or alternative pipeline routes (Tr. 56, p. 140).

With respect to historic significance, the Company described the designation of the existing, retired Edgar Station by the History and Heritage Committee of the American Society of Mechanical Engineers ("ASME") (Exh. BE-48, p. H-1-1). BECo stated that the site is not designated under the National Register of Historic Places, nor does the Company intend to apply for such designation (id.) In addition, the Company noted that inclusion under the ASME designation does not involve restrictive conditions as does the designation under the National Register of Historic Places (id., p. H-1-2). The Company stated that it has chosen materials, colors and siding that would complement the architectural features of the existing, retired Edgar Station (id.).

Weymouth requested that the Siting Board should include a condition stating that BECo would construct, operate and maintain a waterfront park along King's Cove for use by the public (Weymouth Site Banking Brief, p. 6). Weymouth also requested that the condition should include language stating that specific details of the park area, layout, construction methods and materials would be reviewed and coordinated with Weymouth's Waterfront Committee (id.).

169/ In its filing, Algonquin indicates the proposed route effectively balances environmental, safety and cost considerations, and further provides that Algonquin would be willing to work with the Town of Braintree to minimize impacts to the Town Forest (Exh. EBCA RR-7).

WATER argued that the Company has not presented any evidence to support the ability of BECo to obtain the needed zoning exemption from the DPU and points to the withdrawal of BECo's zoning exemption request (WATER Site Banking Reply Brief, p. 3). Further, WATER argued that the actions of Weymouth in regard to amending the zoning by-law, after the Edgar Station was retired in 1978, reflects a negative view by Weymouth to the idea of siting a new generating plant at the primary site (id.). Finally, WATER argued that the Kings Cove Harbor Walk would be an unattractive recreation spot due to the park's location adjacent to the proposed facility (id., p. 8).

(2) Analysis

To begin, the Siting Board notes that BECo has not completed the necessary permitting requirements, specifically the steps concerning zoning and site plan review. The facility has not been subject to any local zoning processes.[170]

However, the Siting Board acknowledges that the existing use of the primary site is industrial in nature and concurs with BECo that the proposed facility would not alter the past use of the site. The Siting Board agrees with the Company that the use of this site would minimize land impacts by using presently disturbed land. In addition, the proposed facility is compatible to the heavy industrial areas to the west and south of the primary site. Further, the Company has endeavored to maintain public access via the Harbor Walk, and proposes to provide a 60-foot wide buffer of trees along Monatiquot Street.

A significant component of the facility's overall land use impacts relates to the location of the natural gas pipeline. The final selection of the route that the pipeline will travel has not been resolved, and due to the length of the routes, which

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170/ The Siting Board notes that the facility cannot be constructed on the primary site without obtaining either a zoning exemption from the DPU or the appropriate zoning variances or a special permit from the Town of Weymouth.

range from 11,175 to 14,950 feet, the impacts are likely to be significant. The length and general routing of the gas pipeline through residential communities detracts from the overall merits of siting the proposed facility at the primary site. Until the final route is approved by FERC, the type and degree of land use impacts cannot be fully identified with certainty. Nevertheless, the Siting Board recognizes that the FERC review process and other state and local permitting reviews provide the forum for ensuring that such a pipeline, if approved, would be routed and installed such as to minimize its land use impacts.

In order to demonstrate that land use impacts are minimized at the primary site, BECo shall comply with the following conditions: (1) BECo shall provide the Siting Board with copies of either a zoning exemption from the DPU or a zoning variance from Weymouth (or special permit from Weymouth, whichever is applicable), indicating that the generating facility can be constructed in said location, and (2) BECo shall construct, operate and maintain a waterfront park along King's Cove for use by the public. Specific details of the park area, layout, construction methods and materials shall be reviewed and coordinated with Weymouth's Waterfront Committee.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to land use, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to environmental impacts.

The record demonstrates that the Company's construction plans with implementation of the aforementioned conditions, as well as FERC's review of Algonquin's proposed natural gas pipeline adequately ensure a minimum impact on the environment with respect land to use.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the aforementioned conditions, the Company has established that the environmental impacts of the proposed facilities at the primary site would be minimized with respect to land use.

g. Visual Impacts

BECo stated that at the primary site the proposed facility would be moderately visible from surrounding areas with partial screening (Exhs. BE-6, p. 5-33; BE-48, p. 31). BECo stated that placement of the proposed facility at the primary site would not result in a major change in visual quality because it would be visually compatible with the Weymouth Fore River landscape (Exhs. BE-6, p. 7-24, BE-59, p. 6.7-2; Tr. 22, p. 23).

BECo stated that the proposed facility, whether built at the primary or alternative site, would include two emission stacks 245 feet in height and 17 feet in diameter (Exh. BE-6, pp. 7-6, 7-7). The Company indicated that the proposed facility also would include two 100-foot high auxiliary boiler stacks and two other buildings with heights of over 50 feet -- a 98-foot high turbine generator building and a 83-foot high heat recovery steam generator building (id.; Exh. HO-E-50). BECo indicated that it did not anticipate any design changes that would result in a change in the proposed stack height of 245 feet (Exh. HO-E-49).[171]

The Company stated that views of the new structures would be obscured by the retired, existing facilities on the site (Exhs. BE-6, p. 7-24, BE-59, p. 6.7-2).[172] The Company provided photographs to illustrate the likely visual impacts of the

171/ The Company stated that the stack height was based on the Good Engineering Practices (GEP) height of two and one-half times the generating facility building height (Exh. HO-E-4). BECo stated that MDEP had given no indication that the proposed stack height would need to be modified (Tr. 22, p. 13).

172/ The Company stated that the existing facilities on the site include two 250-foot high stacks (Exhs. BE-6, p. 7-24, BE-59, p. 6.7-2).

proposed facility at the primary site from five visual receptors: (1) the Idlewell neighborhood in Weymouth, (2) a location approximately one-third mile east of the primary site from the approach on route 3A in Weymouth, (3) a location three-fourths mile west of the primary site, (4) the residential community on Town River Bay in Quincy, and (5) King Oak Hill, 1.5 miles southeast of the primary site in Weymouth (Exh. BE-6, pp. 7-24, Figures 7.3.8-1 to 7.3.8-6).

The Company stated that from Kings Cove and the Fore River Bridge in Weymouth, and Germantown Point in Quincy, views would consist primarily of portions of the proposed facilities not screened by existing facilities (id., p. 7-24). The Company stated that residents of Monatiquot Street in Weymouth, approximately 1,000 feet from the primary site, currently have views of the primary site that are not screened by the existing 60-foot wide buffer (Exh. BE-48, p. 61-B-5).

In order to mitigate visual impacts on Monatiquot Street, the Company proposed a greenbelt of vegetative screening (Exhs. BE-6, p. 7-24, Figure 7.3.8-7, BE-59, p. 6.7-3). The Company proposed to augment the current visual buffer provided by mature deciduous trees by adding evergreen and low deciduous shrubs for on-grade screening and by extending the greenbelt an additional 200 feet beyond the end of Monatiquot Street along the Company's property (Exhs. BE-59, p. 7.7-1, BE-6, Figure 7.3.8-7; Tr. 23, p. 19). In addition, BECo proposed to match the colors of the proposed facilities to those of the retired Edgar Station (Tr. 22, p. 15). The Company has further proposed to build a recreational area near the proposed facility at King's Cove in

Weymouth (Exh. BE-59, p. 6.6-2, Figure 6.6-1).[173] See Section II.D.1.f., above.

The record shows that BECo's proposed facility would include two 245-foot high, 17-foot diameter stacks, which would be visible over significant portions of the surrounding area. However, the proposed height would be similar to that of the stacks at the existing Edgar Station, and the Company would match the colors of the proposed facility to those of the retired existing Edgar Station. In addition, the Company would provide greenbelt improvements and augmentation, limiting visual impacts on nearby Monatiquot Street residences to partial views of the proposed facility. Given the proposed mitigation and the industrial nature of much of the surrounding area, the proposed facility would be compatible with, and would not adversely affect the existing visual environment in the vicinity of the primary site. The Siting Board notes that any remaining incremental impact of the proposed facility could be significantly offset if BECo and Weymouth agree on a plan to remove structures from the top of the retired facility.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to visual impacts, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to visual impacts.

173/ The Company stated that it also was willing to discuss removal of some structures from the top of the retired facility to present a more even view plane than currently exists (Exh. HO-E-47; Tr. 22, p. 11). The Company indicated that while no formal time line had been discussed with Weymouth officials, it estimated that it would take somewhat less than one year for demolition of stacks and existing roof structures and to rebuild roof sections left open by demolition (Tr. 22, pp. 11, 25-26).

The record demonstrates that the Company proposes to implement the facility design and mitigation measures that adequately ensure a minimum impact on the environment with respect to visual impacts.

Accordingly, based on the foregoing, the Siting Board finds that, with implementation of the proposed mitigation, the environmental impacts of the proposed facility at the primary site would be minimized with respect to visual impacts.

h. Traffic

BECo stated that traffic generated by the construction and operation of the proposed facility at the primary site would not have a significant impact on intersections in the vicinity of the site (Exh. BE-59, p. 6.9-3).

The Company indicated that the primary site is bisected by Route 3A (Exh. BE-48, p. T-1-2). The proposed facility, along with the existing Edgar Station and associated facilities would be located on the south side of Route 3A while the proposed water front park along with one existing fuel oil tank would be located on the north side (id.; Exh. BE-6, Figure 2.3-1). The Company indicated that each portion of the site is accessed by a driveway from Route 3A and that the driveways lead to a site roadway system, connecting both portions of the site via a Route 3A underpass (id.).

In order to assess traffic impacts due to construction and operation of the proposed facility, BECo estimated 1993 and 1994 no-build traffic volumes and levels of service ("LOS")[174] for morning and afternoon peak hours of 7:30 am to 8:30 am and 4:45

174/ The Company explained that an LOS designation describes the traffic flow, volume and speed at an intersection (Exh. BE-59, Table 5.11-1). The Company further explained that LOS designations range from LOS A which describes a condition of free flow, low volumes and relatively high speeds and no delays for side street motorists to LOS F which describes a condition of forced flow or breakdown with queuing along critical approaches and unstable operating conditions (id.).

pm to 5:45 pm at intersections in the vicinity of the proposed facility (Exh. BE-48, T-2, T-8). The study area included three intersections and one traffic rotary along Route 3A, to the north and south of the primary site, and the two site driveways (id.).[175] The Company next estimated the maximum number of vehicles that would be required for employees and equipment deliveries during construction and operation of the proposed facility, during morning and afternoon peak hours (Exh. BE-59, pp. 6.9-1, 6.9-2).[176] The Company noted that equipment deliveries to the site would be minimized because most of the heavy equipment would be delivered to the site via barge (id., p. 6.9-1).

BECo then added estimated facility construction traffic to projected 1993 levels and estimated facility operational traffic to projected 1994 levels (id.; Exhs. BE-6, pp. 7-25, 7-26, BE-48, T-2.).[177] The Company's analysis demonstrated that the two site driveways would experience decreases in predicted 1993 LOS due to facility construction traffic (Exh. BE-48, T-2). However, the Company's analysis further demonstrated that facility

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175/ The Company estimated 1993 and 1994 no-build traffic volumes by applying a 2.6 percent annual growth rate to identified 1989 traffic volumes and adding estimated trips associated with specific developments anticipated in or adjacent to the study area (Exh. BE-59, pp. 5.11-4, 5.11-5).

176/ With respect to construction, the Company estimated that peak construction round trips would include 227 employee vehicles and 25 light and heavy trucks for general deliveries (Exh. BE-6, p. 7-25). The Company assumed that all employee trips would take place during the morning and afternoon peak hours and that nine of the truck trips would occur during the peak hours (id.). With respect to operation, the Company estimated that the proposed facility would generate 43 passenger vehicle round trips over three shifts with 32 trips in the peak morning and afternoon hours as well as five truck trips per day (Exh. BE-59, p. 6.9-2).

177/ In estimating impacts the Company stated that it assumed the construction work force would enter the study area during peak hours (Exh. BE-59, p. 6.9-1).

operation would have no adverse impact on traffic conditions (id.).[178] In order to mitigate traffic impacts, BECo proposed to: (1) schedule construction work force arrival/departure times outside the morning and afternoon commuter peak hours; (2) institute right turn only restrictions to and from Route 3A from site driveways;[179] and (3) control traffic exiting via the south drive during the afternoon peak hours (id., T-3, Exh. BE-59, p. 7.9-1). The Company stated that enforcement of the off-peak work force travel would be established with the contractors by means of written agreements and monitored by the construction contract management staff (Exh. BE-48, T-7). The Company maintained that such mitigation strategies would eliminate all decreases in LOS at the site driveways (id., T-3).

Weymouth suggested that the Siting Board specifically require the Company to implement the aforementioned mitigation strategies, should it approve the proposed facility as part of the site banking review (Weymouth Site Banking Brief, p. 11).

The record demonstrates that, based on projected 1993 and 1994 traffic levels in the vicinity of the proposed facility, vehicles required for the construction of the proposed facility would, without mitigation, impact traffic flows at the two approaches to the site from Route 3A. However, the record further demonstrates that the mitigation strategies proposed by the Company would maintain the existing traffic flows.

Therefore, in order to demonstrate that the traffic impacts are minimized at the primary sites, BECo shall comply with the

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178/ The Company indicated that conditions at one site driveway would be reduced from LOS A to LOS B, and would be reduced at the other site driveway from LOS D to LOS F (Exh. BE-48, T-2).

179/ The Company maintained that the proposed right turn restrictions would not impact adjacent intersections within the vicinity of the proposed facility (Exh. BE-48, T-10). The Company indicated that motorists who would turn left leaving or entering the site driveways would travel, instead, along the existing internal roadway to reach the opposite driveway (id.).

condition to implement its proposed traffic mitigation strategies during the construction of the proposed facility, including (1) the scheduling of the construction work force arrival/departure times outside the morning and afternoon commuter peak hours of 7:30 AM to 8:30 AM and 4:45 PM to 5:45 PM; (2) the institution of turning restrictions to and from Route 3A from site driveways; and (3) the control of traffic exiting the site during peak afternoon traffic hours, as needed.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to traffic impacts, including adequate consideration of mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to traffic impacts.

The record demonstrates that the Company's construction plans with the aforementioned conditions adequately ensure a minimum impact on the environment with respect to traffic impacts.

Accordingly, based on the foregoing, the Siting Board finds that, with the implementation of the aforementioned conditions, the environmental impacts of the proposed facility at the primary site would be minimized with respect to traffic impacts.

i. Safety

In this section, the Siting Board reviews safety issues related to the existence of any hazardous substances at the primary site, both within the existing Edgar Station and within the site subsurface, as well as the storage and transport of the hazardous materials that would be required for operation of the proposed facility. BECo asserted that potential impacts to health and safety due to the existence of hazardous substances on the primary site and use of hazardous materials for facility operation would be minimal and that appropriate plans would be implemented to protect public health, safety and the environment

(BECo Initial Brief, pp. 261, 266-268, BECo Site Banking Brief, pp. 45-47).

(1) Existing Edgar Station and Site Contamination

The Company indicated that although the existing Edgar Station contains asbestos, the structure would be left in place because the building is structurally sound, poses no danger to the public and would be extremely costly to demolish (Exh. HO-E-47).[180] However, the WBH expressed concern that the asbestos, which it found to be in various stages of deterioration, could be released into the environment due to the deteriorated condition of the building (Exhs. WBH-7, WBH-8, WAT-8). BECo agreed to fully enclose the existing building in accordance with recommendations of the WBH, and later stated that enclosure had been completed (Exh. Wey-21; Tr. 53, pp. 121-122). The Company noted that, although the WBH had inspected the enclosure, it had not confirmed, in writing, that the work had been done to its satisfaction (Tr. 53, pp. 121-122).

In order to determine the extent of hazardous substances within the site, the Company evaluated subsurface conditions within (1) the vicinity of the existing switchyard which was the site of two transformer oil spills in 1988, and (2) the portions of the site that would be utilized for construction of the proposed facility (Exhs. HO-E-35, HO-RR-48).

With regard to the existing switchyard area, the Company stated that the two transformer oil spills in 1988 were reported to the MDEP and cleaned up, in accordance with the requirements of the MDEP, including excavation and disposal of soils from the

180/ The Company indicated that avoidance of demolition was a consideration in the determination of the location of the proposed facility within the site (Exh. BE-6, p. 2-3). However, the Company noted that if the capacity of the proposed facility were expanded beyond 600 MW, demolition would be required (id., p. 2-4).

spill area (Exh. HO-E-35; Tr. 26, pp. 49-53). The Company indicated that, subsequent to the clean-up of the spills, a hazardous waste evaluation of soil and groundwater at three test-well sites in the vicinity of the transformer oil spills identified hazardous substances in the groundwater and soils (Exh. HO-E-35, attached Gale Report, p. 6). However, the Company also indicated that, based on the industrial nature of the site, planned future use of the area, restricted public access, and lack of drinking water wells within a 2,500-foot area, the evaluation report concluded that the site did not appear to pose an imminent threat to public health, welfare, safety or the environment (id., p. 7; Tr. 26, p. 43).

BECo stated that there were no traces of transformer oil constituents within the portions of the site that would be utilized for construction of the proposed facility, that no construction work was planned within the switchyard area and that it would restrict access to this area during construction (Exh. HO-RR-48, p. 5-1; Tr. 53, pp. 129). In addition, the Company asserted that no further action was planned unless required by the MDEP and that there was no evidence that either of these spills would impact construction or operation of the proposed facility (BECo Initial Brief, p. 266).

With regard to the construction site, the Company indicated that an environmental site assessment[181] had been prepared in order to characterize the soil and groundwater quality conditions

181/ The Company noted that the scope of the environmental site assessment was conducted in accordance with the Massachusetts Oil and Hazardous Materials Release Prevention and Response Act, Chapter 21E of the Massachusetts General Laws ("Chapter 21E") (Exh. HO-RR-48, p. 1-2). The Company stated that the site assessment was submitted to the MDEP as part of the Chapter 21E site assessment process and that, as a next step in the process, the Company would submit plans for site clean-up to the MDEP (Tr. 53, p. 123). The Company stated that, in addition, it plans to apply to the MDEP for classification of the site as a nonpriority site and for a waiver of approval from the MDEP which would allow the Company to proceed with site clean-up without the requirement that the MDEP approve each step (id., pp. 123-124).

within the portions of the site that would be developed for the proposed facility, including the power block[182] and the waterfront park, and to prepare appropriate remediation plans (Exh. HO-RR-48).[183] The Company indicated that contaminants, including polyaromatic hydrocarbons and metals such as lead, arsenic, vanadium and selenium, were detected in the soil and groundwater at both locations (id., p. 5-1, attach. Vol. III, p. ix). However, BECo indicated that the groundwater selenium concentration was the only concentration in excess of promulgated standards and that, in addition, arsenic was detected above naturally occurring levels in the soil at the waterfront park site (id., pp. 4-28, 5-1).[184]

In order to determine if the contaminants detected in the soil would pose a significant risk of harm to human health and the environment, the Company conducted a limited risk characterization of the site (id., attach. Volume III).[185] BECo first identified potential receptors (i.e., construction workers and waterfront park visitors), and potential exposure pathways (i.e., soil and air) (id., pp. viii, ix). BECo next

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182/ In describing the geographical characteristics of the proposed power block site, the Company indicated that the surface area consists of flyash and bottom ash generated by the retired coal-fired units and that the subsurface area consists of flyash and bottom ash, spoils from the dredging of the Weymouth Fore River channel, and construction fill (Exh. BE-59, p. 5.5-1).

183/ The site evaluation also included an assessment of the portion of the site originally proposed for construction of a new fuel oil day tank (Exh. HO-RR-48). However, the Company indicated that this tank has been deleted from the scope of the project (Tr. 53, p. 132).

184/ The Company indicated that it was not aware of any state or federal standards for soil arsenic content (Exh. HO-RR-112).

185/ The Company indicated that human health risks of compounds in groundwater were not evaluated because there is no current or reasonably foreseeable use of the groundwater at the site (Exh. HO-RR-48, Volume III, p. ix).

estimated average daily doses of contaminants, without any remediation, for identified receptors (id., p. ix). The Company then calculated potential carcinogenic and non-carcinogenic risks for each receptor group and concluded that although the carcinogenic risk to construction workers from inhalation exposure to likely levels of fugitive dust would exceed the currently applicable Massachusetts acceptable limit, the site would pose no risk to any other receptor group (Exh. HO-RR-48, pp. 5-1, 5-2, 5-3, Vol, III, p. x).

BECo explained that the existing contaminants would not pose a significant risk to human health or the environment due to: (1) the relatively low level of contaminants at the sites and low mobility of the contaminants detected; (2) restriction of access to the power block area; (3) the existing industrial land use of surrounding areas; and (4) the direction of groundwater flow away from the nearest residential areas toward the Weymouth Fore River (id.).[186] Further, the Company maintained that any increased risk to construction workers could readily be mitigated by construction procedures that would be developed in accordance with state and federal standards and would be incorporated into the remediation plans submitted to the MDEP under the Chapter 21E site assessment process (id., p. 5-2; Tr. 53, pp. 136-137).[187]

Finally, BECo stated that there is little vegetation on the primary site and that vegetation management on the primary site, as well as the proposed waterfront park, would be performed by mechanical means rather than by utilization of herbicides (Exh. HO-E-36).

186/ In addition, the Company noted that it is unlikely that there is a hydrologic connection between the groundwater at the primary site and the closest wells, which are located more than one mile from the site (Tr. 57, pp. 68-71).

187/ The Company explained that construction procedures to limit worker exposure to fugitive dust would include covering of materials, dampening of excavation areas, wind screens and use of respirator equipment by workers (Tr. 53, pp. 136-137).

(2) Transport and Storage of Materials

The Company asserted that appropriate plans and procedures would be undertaken for the delivery, storage and handling of input materials, including fuel oil, lubricants and process chemicals, to ensure safety and protect the environment (BECo Initial Brief, pp. 267-268). With regard to fuel oil, BECo stated that oil tanks would be surrounded by earthen dikes and that the entire diked area would be protected with a buried liner to prevent oil intrusion into the subgrade in the event of a leakage or spill (Exhs. HO-E-32, HO-E-33, BE-6, p. 2-7). The Company further stated that an oil spill contingency plan would be developed prior to the operation of the proposed facility (Exhs. BE-48, OS-1, HO-RR-57A, SP-1).[188] In addition, BECo indicated that lubricating oils would be stored in tanks within a walled concrete area in order to contain any waste oil (Exh. BE-6, p. 2-7).

With regard to process chemicals, the Company indicated the hazardous substances that would be used during operation of the proposed facility, include (1) aqueous ammonia for control of NOx emissions,[189] and (2) sulfuric acid and sodium hydroxide for water treatment regeneration (Exh. HO-E-31).[190] The Company

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188/ The Company noted that it would become a member of the Tri-Cities Industrial Anti-Pollution Committee which coordinates efforts toward containment and cleanup of any oil spills from member companies into the Weymouth Fore River (Exh. HO-RR-57A, SP-1).

189/ The Company noted that under one proposed BACT scenario, natural gas would be fired for 365 days and NOx emissions would be minimized without SCR and thus, aqueous ammonia would not be required (Exh. HO-RR-93, pp. 9-16). See Section II.D.1.a.(1), above.

190/ The Company stated that sodium hypochlorite, which is also classified as a hazardous substance, would be used for condenser cleaning (Exh. HO-E-31). The Company noted that sodium hypochlorite would be stored on site in smaller quantities than other hazardous substances, and would be stored in a 55-gallon drum container designed to ensure proper storage and handling (Tr. 33, p. 95). The Company noted that additional chemicals, stated that these substances would be stored in dedicated, closed tanks surrounded by dikes to contain any accidental releases (Exh. HO-E-34).[191] BECo maintained that all storage tanks would be constructed and installed in accordance with applicable federal, state and local standards and regulations (Exh. HO-E-74).

With regard to the transport of process chemicals, the Company indicated that approximately eight, 5,000-gallon tank truckloads of ammonia would be required every two months during gas firing and every two weeks during oil firing (Exh. HO-RR-46). The Company provided that procedures would be developed in conjunction with Weymouth to ensure the safe unloading of the ammonia (Tr. 28, p. 162). BECo indicated that approximately one tank truck of sulfuric acid would be required each week, and that the storage and unloading area would be provided with spill containment as well as protection for personnel, such as eye wash stations (Exh. HO-RR-53). The Company stated that transportation

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classified as hazardous, would be used to clean the heat recovery steam generators, but that these chemicals would not be stored on site or used to support day to day operation (Exh. HO-E-31).

191/ The Company explained that ammonia, should it be used, would be stored in two 20,000-gallon carbon steel tanks that would each be surrounded by a secondary containment dike underlain with an ammonia resistant ground liner (Exhs. HO-DE-2, HO-E-34, HO-E-75; Tr. 28, pp. 158-160). The Company stated that, in addition, the containment dikes site would have completely enclosed roof systems which would prevent the escape of ammonia fumes in the unlikely event of a spill, and also prevent the entrance of rain or snow into the spill containment area (Exh. HO-E-75). The Company noted that the ventilation system proposed for the enclosed dike area and storage tank also would be designed to prevent the release of fumes to the atmosphere (Exh. HO-RR-57A, SP-2). The Company added that the location of the ammonia storage tanks, near the SCR system, would minimize piping and valve requirements (Exh. HO-DE-2).

The Company further explained that sulfuric acid would be stored in a 7,000-gallon carbon steel tank which would be surrounded by a concrete containment wall, and that a layer of crushed limestone would be provided within the containment area to effect immediate neutralization of any leaks or spills (Exh. HO-RR-53).

of hazardous substances would be regulated by the U. S. Department of Transportation (Exh. HO-E-31).

BECo indicated that an Emergency Response Plan would be prepared which would delineate all hazardous materials stored onsite, emergency equipment located onsite, and procedures to be implemented in the event of an emergency (Exh. HO-RR-57A, SP-3). In addition, the Company stated that a fire protection system, that would utilize the existing Edgar Station fire protection system to the greatest extent possible including the existing on-site hydrant system, would be installed to comply with all federal, state and local fire codes (Exhs. HO-E-37, BE-6, p. 2-4, WEY-27). The Company stated that 270,000 gallons of water, originating from the City of Quincy, would be held in emergency reserve within the raw water storage tank for fire fighting purposes (Exh. WEY-27). The Company maintained that this amount was sufficient for fire fighting purposes, but that, in the event of a severe fire, adequate supplementary supplies would be available under both the proposed and backup water supply plans (Tr. 54, pp. 12-14).[192] Finally, the Company noted that the spent SCR catalyst material, if required for NOx removal, would be considered hazardous waste but would be disposed of by the catalyst manufacturer (Exhs. HO-E-65, HO-RR-93, p. 15).

Weymouth requested that the Siting Board specifically require the Company to review its plans for the storage, containment and transport of aqueous ammonia with the Local Emergency Planning Committee, prior to finalization of construction design (Weymouth Site Banking Brief, pp. 7-8). In addition, Weymouth requested that the Siting Board specifically require the Company to include Weymouth in the development of the

192/ The Company indicated that, under the backup water supply plan -- the barge supply option -- an oil tank with an 80,000 barrel capacity would be converted to back-up water storage, while under the proposed water supply plan -- the City of Quincy option -- additional supplies would be obtained from the water pipeline that would extend to the site (Tr. 54, pp. 12-14).

scope of the Emergency Response Plan and to review said Plan, prior to construction and periodically during operation of the proposed facility, with the Local Emergency Planning Committee, the Fire Department and other appropriate local officials (id., p. 8, citing Exh. HO-RR-57A, SP-3). Finally, Weymouth requested that the Siting Board specifically require the Company to review its plans for maintaining an adequate supply of water for fire fighting purposes with the Weymouth Fire Department and to revise such plans as necessary to address any concerns of the fire department (Weymouth Site Banking Brief, p. 11).

(3) Analysis

With respect to the existing Edgar Station, the record indicates that the Company has agreed to completely enclose the building, in accordance with recommendations of the WBH, in order to prevent the release of asbestos into the atmosphere. Although the Company stated that such enclosure is complete, the Siting Board notes that the WBH has not confirmed, in writing, that the enclosure complies with its recommendations. Accordingly, the Company shall comply with the condition to submit written confirmation from the WBH that the existing Edgar Station has been enclosed in accordance with its recommendations at the time the Company submits its final application.

With respect to existing subsurface conditions, the record demonstrates that hazardous substances are present within the site soils and groundwater within the vicinity of two previous oil spills and within proposed construction areas. However, the record also demonstrates that the oil spills have been cleaned up in accordance with MDEP regulations and procedures, that no construction would take place in the vicinity of the oil spills, and that access to this area would be restricted during construction. The record also demonstrates that contaminants would not pose a significant risk to human health or the environment and that site remediation and worker protection plans for the construction areas would be developed in conjunction with the MDEP. However, in light of planned recreational use of the waterfront park, the Siting Board notes its concern regarding the concentration of arsenic in the soil that exceeds naturally occurring concentrations. The Siting Board expects that such contamination of the waterfront park soil would be specifically addressed in the aforementioned site remediation plans.

With respect to the storage and transport of hazardous materials, the record indicates that the off-site transportation and disposal of such materials would be subject to applicable standards, including those of the U. S. Department of Transportation, and that the Company intends to develop contingency plans for accidental release of materials, including an oil spill contingency plan that would be coordinated with neighboring industries and an Emergency Response Plan.

Weymouth requests that its officials be provided with the opportunity to participate in defining the scope of the Emergency Response Plan and that its Local Emergency Planning Committee, Fire Department and other pertinent local officials be allowed to review the Emergency Response Plan both prior to construction and periodically during operation of the proposed facility. The Siting Board agrees with Weymouth that local participation in defining the scope of the Emergency Response Plan and subsequent review of the Plan by local agencies, prior to construction of the proposed facility and periodically during its operation, would be appropriate. The Siting Board notes that similar plans found to be acceptable in previous Siting Council decisions included provisions for local review. <u>Enron</u>, 23 DOMSC at 214-216; <u>MASSPOWER</u>, 20 DOMSC at 399-401; <u>Altresco-Pittsfield</u>, 18 DOMSC at 406-408. Thus, the Company shall comply with the condition to provide for Weymouth participation in the development of its Emergency Response Plan and for review of the plan, by appropriate local agencies, prior to construction and periodically during operation of the proposed facility.

With regard to the storage, containment and transport of ammonia, the Siting Board agrees with Weymouth that the specific details of the Company's plans for the storage, containment and transport of aqueous ammonia should be reviewed by the Local Emergency Planning Committee prior to finalization of construction design. Thus, the Company shall comply with the condition to provide for the review of its plans for the storage, containment and transport of aqueous ammonia by the Weymouth Emergency Planning Committee. In addition, the Siting Board notes that in previous reviews of generating facilities utilizing ammonia, applicants provided dispersion modeling data which demonstrated that the expected concentration of ammonia at the site boundary would not exceed a level of 500 ppm under worst case conditions of ammonia release or demonstration that mitigation measures included in facility design, such as enclosed containers, would ensure that ammonia concentrations would not exceed 500 ppm at the site boundary under the same conditions. Enron, 23 DOMSC at 221; MASSPOWER, 20 DOMSC at 399-400; Altresco-Pittsfield, 17 DOMSC at 406. Here, the Company has stated its intent to completely enclose the ammonia containment area and include a vent system designed to prevent the release of ammonia fumes into the atmosphere. Nonetheless, the Company should provide a description of the potential for any vent release leaks and the impact of any such leaks on site boundaries, under worst case conditions of ammonia release in its final petition.

Finally, with regard to the adequacy of water supplies for fire fighting purposes, the Siting Board agrees with Weymouth that the Company should review plans with the Weymouth Fire Department and revise plans as necessary. Thus, the Company shall comply with the condition to review its plans for maintaining an adequate supply of water for fire fighting purposes with the Weymouth Fire Department, prior to construction of the proposed facility, and to revise plans, as necessary, to address any concerns raised by the Weymouth Fire Department.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to safety impacts, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to safety impacts.

The record demonstrates that the Company's construction plans, with implementation of the aforementioned conditions and mitigation measures, as well as review and oversight of facility design and construction and transport of hazardous substances by appropriate agencies, adequately ensure a minimum impact on the environment with respect to safety impacts.

Accordingly, based on the foregoing, the Siting Board finds that, with implementation of the aforementioned conditions, the environmental impacts of the proposed facility at the primary site would be minimized with respect to safety impacts.

j. Electric and Magnetic Fields

BECo stated that the electrical transmission interconnect between the proposed facility and the existing switchyard at Edgar Station would be made via three underground connections within the station itself, which would have negligible impact on the electric and magnetic fields ("EMF") off-site or at the edge of any transmission ROW (Exh. HO-E-63).[193]

The Company stated that the electrical power output from the proposed facility would, upon leaving the switchyard, be supplied to the area power system on existing BECo-owned 115 KV overhead transmission lines that extend along BECo's ROW 4 between Edgar Station and Holbrook, Massachusetts (id.).

BECo provided the Siting Board with calculations of expected 60 cycles per second ("Hertz") EMF levels at the edges

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193/ Electric fields and magnetic fields produced by the flow of electricity are collectively known as electric and magnetic fields or EMF.

of the ROW based on: (1) horizontal and vertical dimensional coordinates at the center of the transmission line span; (2) conductor size; (3) net ampere loading; and (4) phase relations for the individual conductors (id.).[194] The Company's analysis indicated that, at an output level of 300 MW, the highest electric field would be .30 Kilovolts per meter, and that the highest magnetic field would be 8 milligauss.[195] BECo indicated that these levels would be below existing levels (Exh. HO-E-63).

BECo acknowledged the existence of several industry practices utilized to mitigate EMF on transmission lines, such as use of particular line configurations, phase spacing, and rolling of phases on adjacent circuits (id.). The Company indicated that two existing transmission lines located on its ROW 4 utilize partial phase rolling techniques which result in an approximate 30 percent reduction from the field levels that would be experienced with standard parallel phase construction (id.)[196]

BECo stated that additional phase reconfiguration could be implemented to reduce EMF levels for circuits expected to carry a portion of the power from the proposed facility (Exh. HO-RR-116). The Company stated that such a reconfiguring of phases would not be a simple task, and that in the specific case of the ROW 4 circuits, modifications would be required not only at both of the affected BECo substations, but also at up to five additional utility substations supplied by these transmission lines (id.).

194/ Standard U.S. powerline frequency is 60 Hertz.

195/ See Table 2, attached, for complete data regarding the Company's calculations of EMF levels for the primary site.

196/ The Siting Board notes that BECo's existing transmission lines are not ancillary facilities as defined in G.L. c. 164, § 69G. However, in order to allow comprehensive analysis and comparison of environmental impacts of the proposed facilities at either site, the Siting Board may address any potentially significant effects of such facilities on EMF levels along existing transmission lines.

In a previous review of proposed transmission line facilities which included 345 KV transmission lines, the Siting Board accepted edge of right-of-way levels of 1.8 KV/meter for the electric field, and 85 milligauss for the magnetic field. Massachusetts Electric Company, 13 DOMSC at 119, 228-242 (1985) ("1985 MECo Decision"). Here, the Siting Board notes that the edge of ROW EMF levels for transmission lines serving the primary site (115 KV transmission system) are well below the levels found acceptable in the 1985 MECo decision. In addition, operation of the proposed facility would decrease, rather than increase, the EMF levels along ROW 4 under normal load conditions.

Nevertheless, the Siting Board suggests that BECo further consider implementation of phase arrangements and/or extend all reasonable efforts to utilize any other known cost-effective mitigation techniques to further minimize EMF levels along the affected existing transmission lines.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the primary site with respect to EMF, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to EMF.

The record demonstrates that the Company's construction plans include reasonable efforts to implement measures to minimize EMF impacts on portions of the existing transmission system affected by the proposed facility, and adequately ensure a minimum impact on the environment with respect to EMF.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the primary site would be minimized with respect to EMF.

2. Cost of Proposed Facilities at the Primary Site

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility at the primary site to allow the Siting Board to determine if an appropriate balance would be achieved between environmental impacts and cost.[197] The Siting Board also compares the estimated costs of siting the proposed facility at the primary and alternative sites.

The Company estimated a total direct cost of $210,085,606 for materials and labor for the proposed facility at the Edgar site including: $15,722,945 for site work, structures, yard and building services; $32,755,000 for the heat recovery system generator and appurtenances; $103,131,000 for the steam turbine 2and combustion turbine generator sets; $30,599,000 for plant systems and equipment; $5,037,361 for transmission interconnection; $1,231,000 for start-up and testing; $37,411,600 for direct labor costs; and $21,141,300 for scope additions, additional investments and improvements, and labor cost differential (Exhs. HO-RR-120, Table AS-5-2, HO-RR-57A, p. AS-5-9).[198,199]

197/ In past facility decisions, we have evaluated whether estimates of costs for the construction and operation of proposed facilities are realistic for a facility of the size and design proposed. Enron, 23 DOMSC at 132, EEC, 22 DOMSC at 135. Application of that standard of review is consistent with our statutory mandate to minimize environmental impacts of proposed facilities at the lowest possible cost. In this site banking review, we address estimated costs only to the extent necessary to allow a comparison between the primary and alternative sites based on environmental impacts, reliability and cost. It is likely that estimated costs of the proposed facility will have changed significantly at such time as BECo files a final petition for approval to proceed with the project. At that time, the Siting Board would address the consistency of the estimated costs of the proposed facility with our least-cost standard.

198/ All costs are given in 1994 dollars and reflect capability for 320 to 365 days of natural gas-fired combustion and SCR for NO_x control.

199/ The Company provided a comparison of costs at the Edgar and Ironstone sites with and without LDC cost sharing of certain capital costs (Exhs. HO-RR-120, HO-RR-121). However, no LDC cost sharing contract has been signed at either site

The Company indicated that certain of these costs would be site dependent, including overall labor costs and costs for six facility elements: (1) site procurement, (2) site preparation and foundations, (3) heat rejection system components, (4) electric power transmission, (5) fuel handling, and (6) municipal improvements (BECo Phase I Brief, p. 197; BECo Site Banking Brief, pp. 28-29; Exh. HO-RR-121, Table AS-5-1).

Specifically, the Company stated that there would be no site acquisition cost for the primary site because the Company already owned the property, but indicated that conditions at the site would require a driven pile type of foundation (Exhs. HO-RR-121, Table 1, BE-6, p. 5-25, HO-RR-57A, p. AS-5-5; BECo Site Banking Brief, p. 29). The Company further indicated that a once-through cooling system would be utilized at the primary site for heat rejection (Exh. HO-RR-57A, p. AS-5-5). The Company stated that it would interconnect to existing transmission lines at the primary site and as necessary utilize an existing 268,000 barrel tank with a 30-day distillate oil storage capability and associated fuel offloading and transfer facilities (Exhs. HO-RR-57A, pp. AS-5-6, AS-5-7, Table AS-5-2, HO-RR-121, Table 1).[200] Finally, the Company estimated a cost of $2,400,000 for

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(Exh. HO-RR-98). Furthermore, a determination of the number of days when the proposed facility would be gas-fired versus oil-fired depends on a determination by MDEP of BACT for the reduction of air pollution. (See Section II.D.1.a.(1)(a) above). At least one technology/fuel mix combination currently under consideration by the Company, dry NO_x control without SCR, would be possible only with use of 100 MW combustors and with 365 days natural gas firing (Exh. HO-RR-93, Tables 3, 4). Since a full year of natural gas firing would preclude LDC cost sharing at either the primary or alternative sites, the cost analysis herein has been based on a comparison of differential costs without LDC cost sharing.

200/ The UE&C fuel handling system cost estimate was based on construction of a 268,000 barrel fuel oil storage tank, a 1,000,000 gallon fuel oil day tank, railroad track, fuel oil storage tank dike and fire protection system and an unloading facility (HO-RR-57A, p. AS-5-7).

municipal improvements associated with locating the proposed facility at the Edgar site, including construction of a waterfront park and commitments to the Town of Weymouth such as funding a health study to be conducted by the WBH (Exhs. HO-RR-121, Table 1, HO-RR-57A, p. AS-5-8). See Section II.D.1.a.(4) above.

The Company also provided estimates of selected operating costs which are expected to be site-dependent, including gas supply costs, costs related to heat rejection and water supply costs (Exhs. HO-RR-57A, Tables AS-5-7 to AS-5-12, BE-120, Tables 4-1 to 4-26, HO-RR-121). With respect to gas costs, the Company estimated that the net present value ("NPV") life cycle gas cost at the Edgar site would be $1,218,827,356 (HO-RR-121, Table 4).[201] With respect to heat rejection costs, the Company explained that the once-through cooling system at the Edgar site would result in a cost advantage relative to the closed-cycle cooling system required at the alternative site, reflecting both a lower heat rate and lower operating costs for internal pumping (Exh. HO-RR-57A, pp. AS-5-12, AS-5-13).

The Company also provided a comparison of NPV costs for four preferred water supply options over the period 1994-2013, under various combinations of water demand reduction measures (Exh. BE-120). See Section II.D.1.e., above. The Company stated that it selected its proposed water supply plan, purchase of water from the City of Quincy, as the most viable, cost effective water source available to the proposed project at the primary site (Exh. BE-120, pp. 1-3, 5-4).[202,203] The Company also

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201/ With LDC cost sharing of certain capital costs, the Company estimated its share of life cycle gas supply costs as $1,138,930,163 (Exh. HO-RR-121, Table AS-5-11).

202/ The Company stated that it identified barge transshipment of water from the Company-owned New Boston Station as its backup water supply plan (Exh. BE-120, p. 1-2 and 1-3). The Company also selected two other sources of water supply, desalinated water from the Weymouth Fore River and wastewater from the MWRA, for detailed evaluation (Exh. BE-120, pp. 1-2 to identified (1) use of dry combustors for NO_x control, and (2) the on-site collection and re-use of stormwater as its preferred combination of water use reduction provisions (Exh. BE-120, p. 5-3). See Section II.D.1.e., above.

The Company estimated 1994-2013 NPV costs for its four preferred water supply options, assuming use of dry combustors and on-site stormwater re-use, as follows: $18,837,610 for the proposed water supply plan; $27,482,618 for the backup water supply plan; $25,613,818 for MWRA wastewater reuse; and $50,463,773 for on-site water desalinization (Exh. BE-120, Tables 4-6, 4-11, 4-16, 4-21). The Company indicated that the total NPV costs for the proposed water supply plan include 1994-2003 NPV operating costs of $4,761,175 for water purchase and $3,114,760 for on-site water treatment (Exhs. BE-120, Table 4-6, HO-E-106; Tr. 57, p. 140).[204]

As part of its revised BACT analysis, the Company provided cost differentials to compare the capital costs and levelized annual costs of different facility designs (Exh. HO-RR-93S, Appendix, p. A-2).[205] For the two alternative design options that the Company has recommended as BACT in its revised analysis, the Company's cost comparison shows the following differences from the overall facility cost estimates identified above:

1-3).

203/ The Siting Board notes that water requirements may vary depending on BACT determination. Costs are not included for the water use that would be required for either of the BACT alternatives for NOx control. See Section II.D.1.e.(1).

204/ The Company identified the capital costs (1994 dollars) for the water supply options as follows: $7,714,900 for the proposed water supply plan; $8,110,145 for the backup water supply plan; $12,374,089 for MWRA wastewater reuse; and $23,645,700 for on-site water desalinization (Exh. BE-120, Tables 4-11, 4-16 and 4-21).

205/ See Section II.D.1.a.(1)(a), above for discussion of the Company's revised BACT analysis and eight alternative design options.

(1) the natural gas proposal -- 365 days of gas-fired generation using 100 MW dry combustors without SCR -- would reduce capital costs by $8,581,160 but increase levelized annual cost by $8,513,000 per year; and (2) the emission offset proposal -- 320 days of gas-fired generation and 45 days of oil-fired generation using 100 MW dry combustors with SCR for oil-fired generation only -- would increase capital costs by $2,533,500 and increase levelized annual cost by $5,998,000 per year (id.).[206,207]

The Company has provided estimates of the overall costs of the proposed facility at the primary site, as well as components of capital and operation costs which are site dependent. In addition, the Company has developed cost estimates for a range of combustor and fuel use designs, and for a range of specific options to supply process water at the primary site.

The Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility at the primary site to allow the Siting Board to determine whether

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206/ The Company's levelized annual cost differentials include net plant output penalties of $4,594,000 per year for the first BACT recommendation and $7,407,000 per year for the second BACT recommendation, relative to the facility design reflected in the Company's overall facility cost estimate (Exh. HO-RR-93, Appendix, p. A-2). The penalties are based on assumed net plant outputs of 315.21 MW for the first BACT recommendation and 312.35 MW for the second BACT recommendation, as compared to 320.42 MW for the design reflected in the overall facility cost estimate (id.).

207/ The Company estimated the cost per ton of NOx and ammonia removed, relative to a conventional combustor design with no NOx controls, as $931 per ton under the natural gas proposal and $562 per ton under the emissions offset proposal (Exh. HO-RR-93, Table 3). With respect to three alternative designs which minimize water requirements, the Company estimated the costs of NOx and ammonia removal as $2,860 per ton for a design based on 365 days of gas-fired generation without power augmentation or SCR, $2,129 for the same design except with SCR, and $901 per ton for a design based on 320 days of gas-fired generation and 45 days of oil-fired generation without power augmentation and with SCR (id.).

an appropriate balance would be achieved among environmental impacts and cost.

3. Conclusions on the Proposed Facilities at the Primary Site

In this section, we review the consistency of the proposed facility with our overall review standard, requiring that an appropriate balance be achieved among environmental impacts and costs.[208] Such balancing includes trade-offs among conflicting environmental impacts as well as trade-offs among respective environmental impacts and cost.

The Siting Board has found that, based on the implementation of the facility design and mitigation specified in Section II.D.1., the environmental impacts of the proposed facility at the primary site would be minimized with respect to surface water quality/wetlands, land resources, noise, land use, visual impacts, traffic, safety, and EMF.

In addition, the Siting Board has found: (1) that the Company did not provide sufficient information for the Siting Board to determine whether the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality; and (2) that the Company did not establish that the environmental impacts of the proposed facility at the primary site would be minimized with respect to water supply.

208/ The Siting Board notes that, given the information presented by the petitioner at this time, the reliability of BECo's project is comparable at the primary and alternative sites. Therefore, reliability of supply is not addressed in this decision. Further, the issue of reliability is most relevant to the statutory requirement that the Siting Board ensure a necessary energy supply for the Commonwealth. EEC, 22 DOMSC at 315. Need for the facility is not addressed in this decision and is deferred until such time as the Company decides to file with the Siting Board a final petition for the construction of the proposed project. At that time, the Siting Board will evaluate the reliability impacts of appropriate components of the proposed facility.

Finally, the Siting Board has found that the Company provided sufficient information on the costs of the proposed facility at the primary site to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and cost.

The record indicates there are no significant issues involving the balance among surface water quality/wetlands, land resources, noise, land use, visual impacts, traffic, safety and EMF, nor between any of these concerns and air quality, water supply or cost. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the primary site would be minimized with respect to surface water quality/wetlands, land resources, noise, land use, visual impacts, traffic, safety and EMF, consistent with minimizing cost and other environmental impacts.

To complete its review, the Siting Board must address two further issues: (1) whether environmental impacts with respect to water supply would be minimized, consistent with minimizing cost and other environmental impacts; and (2) whether environmental impacts with respect to air quality would be minimized, consistent with minimizing cost and other environmental impacts. The Company's analyses as discussed in Sections II.D.1.a and II.D.1.e suggest that there are trade-offs between water supply and air quality, as well as trade-offs between the respective environmental concerns and cost. Therefore, the Siting Board must address the balance between water supply, air quality and cost.

As described in Section II.D.1.a(1), above, the Company compared the air quality impacts, water requirements and overall facility costs for a range of fuel/combustion design alternatives, and recommended two such alternatives -- both variations of the base dry combustor design -- as BACT. The Company also compared in detail the environmental impacts and costs of a range of water supply alternatives for meeting a 385,000 gpd water requirement -- reflecting use of the base dry combustor design with on-site stormwater reuse -- and selected two such alternatives as its proposed and backup water supply plans.

With respect to the balance between air quality and cost, the Siting Board was unable to make findings as to whether environmental impacts would be minimized with respect to air quality, even before considering costs. In making no finding, the Siting Board cited the lack of documentation to support the Company's claims as to the environmental impacts of its emission offset proposal, as well as the Siting Board's expectation that the choice of an appropriate design would continue to be significantly affected by technological advances prior to implementation of the proposed project.

The Siting Board notes further that the cost information provided by the Company regarding the natural gas proposal and the emission offset proposal, while sufficient to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and costs, is not so disparate as to pose a compelling reason to choose or reject either design pending more definitive evidence of relative environmental impacts.[209] Accordingly, based on this record, the Siting Board makes no findings as to whether the environmental impacts of the proposed facility would be minimized with respect to air quality, consistent with minimizing costs and other environmental impacts.

Nonetheless, we note that the record includes no identified design that would result in smaller air quality impacts than the Company's natural gas proposal, considering facility emissions alone, without offsets. Thus, in the absence of significant further technological changes, should the Company provide sufficient documentation of the emissions reduction potential of

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209/ The Company's estimated costs of NOx removal under its two BACT recommendations are $931 per ton under the natural gas proposal and $562 per ton under the emission offset proposal (see Section II.D.2) the Company's emission offset proposal to support a specific choice between the Company's two BACT proposals, the Siting Board would be able to determine, with respect to emissions of PSD pollutants, whether the environmental impacts of the proposed facility at the primary site would be minimized.

With respect to water supply, our finding that the Company failed to establish that environmental impacts would be minimized was based on the Company's failure to incorporate identified mitigation measures. Specifically, while the Company identified three design alternatives requiring only 44,600 gpd of water, the Company did not propose any of these designs. The Company's two BACT recommendations, in contrast, involve the highest water requirements of any of the designs considered by the Company -- each over 650,000 gpd. In relative terms, the 385,000 gpd water requirement under the base dry combustor design represents an intermediate level of water supply impact.

The Company provided considerable evidence to support its claim that 385,000 gpd could be supplied by the MWRA system via the City of Quincy system, noting in particular that the MWRA system safe yield provides a 21 mgd surplus relative to current systemwide demand. However, BECo did not address the long-term ability of the MWRA to meet higher water requirements under its BACT recommendations.[210] Thus, the Siting Board is concerned about the identified water requirements of over 650,000 gpd under both BACT recommendations, and the Company's failure to address the environmental impacts of such requirements.

210/ Although those requirements are only a little over three percent of the 21 mgd surplus, the MWRA is the sole or principal supplier of water to a sizable service area, and possible system expansions to meet future demand could involve substantial costs and environmental impacts. In addition, BECo cited a savings of 135,000 gpd in water requirements as the reason for shifting to dry combustor technology in the first place, but now recommends dry combustor designs with larger water requirements than the original conventional combustor design.

With respect to the balance between water supply and cost, the Siting Board notes that, relative to the three designs that would minimize water requirements, the Company's two BACT proposals would provide lower combined emissions of NOx and ammonia at lower or comparable cost, and the base dry combustor design would provide comparable emissions of NOx and ammonia at a lower cost.[211]

Considering the combined cost and air quality disadvantages of each of the alternative designs that minimize water requirements, relative to the designs the Company is willing to pursue -- the natural gas proposal, the emission offset proposal, and the base dry combustor design -- the record does not support a conclusion that any of the designs that minimize water requirements is on balance superior. Recognizing that the three designs that minimize water requirements all omit power augmentation, it thus appears that some level of power augmentation may be appropriate to reduce air emissions and costs per unit power output, despite an associated increase in water requirements.

However, the Company failed to establish the basis by which it determined the level of power augmentation under the base dry

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211/ One of the three designs that minimize water requirements, based on the 100 MW dry combustors assuming 365 days of gas-fired generation without SCR or power augmentation, would result in facility NOx emission of 2.37 pounds per net kWhr -- a rate second only to the 2.26 pounds per net kWhr of such emissions under the Company's first BACT recommendation. However, the NOx removal cost of $2,971 per ton for that design is at least several times greater than the corresponding costs for the base dry combustor design and the Company's two BACT recommendations, all of which are less than $1,000 per ton.

The remaining two designs that would minimize water requirements incorporate 110 MW dry combustors and SCR without power augmentation -- one design including and one design not including 45 days of oil-fired generation. The two SCR-based designs would result in combined emissions of NOx and ammonia of over 2.9 pounds per net kWhr, and would incur NOx removal costs of $901 per ton with 45 days of oil-fired generation and $2,129 per ton without oil-fired generation.

combustor design and its two BACT recommendations. In the absence of explicit justification for the underlying levels of power augmentation, it is unclear whether the air emissions and costs advantages apparently afforded by these designs justify the relatively high level of water requirements under its BACT recommendations.[212]

Based on the foregoing, the Siting Board makes no findings as to whether the environmental impacts of the proposed facility at the primary site would be minimized with respect to water supply, consistent with minimizing cost and other environmental impacts.[213] In its final petition, we would expect the Company

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212/ The Siting Board notes that in supporting a water requirement of 385,000 gpd, as part of the base dry combustor design, the Company pointed to its efforts to minimize water requirements through 215,000 gpd of water reduction measures and prospective additional savings stemming from likely Company contributions to leak protection programs. In now advancing its BACT recommendations, the Company can no longer include the 135,000 gpd portion of water use reduction associated with substitution of dry combustor technology, as that would be more than offset by increased power augmentation. The Company's water use reduction efforts thus would be significantly smaller under the BACT recommendations, both in absolute terms and as a percentage of the higher water requirements under such designs.

213/ In regards to the Company's selection of proposed and backup water supply plans, the record indicates that both plans would rely on MWRA supply resources, which are adequate to meet the needs of the proposed facility and existing water users until at least 2000 and possibly 2020. Based on a 385,000 gpd water requirement, the proposed water supply plan is the least costly and requires only limited off-site improvements.

The backup water supply plan is approximately 50 percent more costly than the proposed plan, and is marginally more costly than one of the other preferred alternatives -- use of MWRA wastewater. Further, the Company failed to address various potential environmental impacts of barging under the backup water supply plan, such as air emissions and fuel handling risks. Thus, the Company failed to develop adequate information to compare the environmental impacts of the backup water supply plan and the alternative of using MWRA wastewater. Therefore, the Company failed to establish that, in the event it cannot proceed with the proposed water supply plan, use of the backup plan would ensure minimization of environmental impacts consistent with minimizing costs.

to provide additional analysis to support a level of facility water requirements greater than 385,000 gpd, if proposed. Such analysis should describe and evaluate the trade-offs between air quality impacts, water requirements and cost for a range of power augmentation levels, sufficient to justify the level of power augmentation selected. In addition, such analysis should identify specific options for Company participation in water conservation, source protection and source development efforts, in conjunction with the water supply planning of the MWRA and local communities, capable of offsetting a meaningful share of the Company's water requirements. Should the Company provide the above analysis, in conjunction with use of the proposed water supply plan, the Siting Board would be able to determine whether environmental impacts of the proposed facility at the primary site would be minimized with respect to water supply, consistent with minimizing air quality impacts and cost.

E. Analysis of Proposed Facilities at the Alternative Site

1. Environmental Impacts of Proposed Facilities at the Alternative Site

a. Air Quality

(1) Description

BECo indicated that ambient air impacts would generally be less within the Ironstone site area than the Edgar site area (Exh. HO-RR-109). In order to estimate the air quality impacts at the Ironstone site, the Company performed screening-level analysis using dispersion models and assumptions consistent with the screening level analysis conducted for the Edgar site (id.).[214] The Company then compared the Ironstone screening

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214/ In conducting screening level analysis for the Ironstone site, the Company utilized the same assumptions regarding meteorology and facility design that were used for the Edgar site, but used differing inputs regarding terrain and urban or rural dispersion coefficients (Exh. HO-RR-109, attach. p. 2).

level analysis to the Edgar screening level analysis and determined that, based on differences in terrain, surrounding land use and existing site structures, maximum impacts at the Ironstone site would be approximately 73 percent of the maximum impacts at the Edgar site (id.). BECo then estimated air quality impacts at the Ironstone site by multiplying Edgar refined modeling results by 0.73 (id.).

With regard to CO and NOx emissions, BECo indicated that its analysis demonstrated that impacts at the Ironstone site would be below significant levels, demonstrating compliance with NAAQS without further modeling (id.). With regard to PM-10 and SO_2 emissions, the Company indicated that impacts would exceed significant levels and that therefore, more comprehensive analysis, including interactive source modeling and the addition of ambient background levels, would be required to demonstrate compliance (id.). However, BECo did not evaluate the existing ambient background concentrations at the Ironstone site (id., attach. p. 4). Instead, in order to assess background air quality at the Ironstone site, the Company compared the land use, population density and presence of other major emissions sources within the Ironstone site area to the Edgar site area,[215] and reviewed existing Massachusetts, Connecticut and Rhode Island emissions data for the Ironstone site area (id., p. 2, attach. pp. 5-6). BECo concluded that, based on the rural nature of the Ironstone site area and minimal number of emissions sources in the region, it is highly likely that background concentrations would be lower at the Ironstone site (id.). Thus, the Company

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In addition, screening level analysis at the Edgar site included the downwash effects of the existing generating structure at that site (id.).

215/ The Company noted that the Edgar site was located within a heavily developed urban/industrial area while the Ironstone site area was rural, with less commercial/industrial development and fewer emissions sources (Exh HO-RR-109, attach., p. 5).

further concluded that the Ironstone site region would have a greater air quality margin for growth than the Edgar site region, and that operation of the proposed facility at the Ironstone site would meet all air quality standards (id., attach. p. 6).

Even though air quality impacts would comply with existing standards by a wider margin at the Ironstone site, BECo asserted that the key determinant in comparing the two sites was compliance with NAAQS rather than margin of compliance (BECo Site Banking Brief, p. 17). Thus, BECo maintained that air quality impacts would be equivalent at the two sites (id.). However, BECo maintained that location of the proposed facility at the Ironstone site which is close to the Rhode Island border would likely require Rhode Island as well as Massachusetts permitting, and on this basis, BECo considered the Edgar site to be preferable (id.).

(2) Analysis

The record demonstrates that the Company assessed the air quality impacts of the proposed facility at the alternative site using quantitative and qualitative means. The Company performed the first step of a dispersion modeling analysis -- a screening level analysis -- and then estimated facility impacts by scaling results of the Edgar refined modeling analysis based on a comparison of the screening level analysis for the two sites. BECo compared land use, emissions sources and other characteristics of the two sites and then estimated background concentrations at the Ironstone site. The Company concluded that these concentrations are likely to be less than background concentrations at the Edgar site. BECo then concluded that air quality impacts of the proposed facility would be less at the Ironstone site than at the Edgar site, but that neither site was preferable with regard to air quality since operation of the proposed facility at either site would comply with all air quality regulations.

For the reasons set forth in Section II.D.1.a., above, the Siting Board determined that it would be premature at this time to determine whether air quality impacts of the proposed facility at the primary site have been minimized. Similarly, it would be premature for the Siting Board to determine, at this time, whether the air quality impacts of the proposed facilities at the alternative site have been minimized.

Therefore, the Siting Board finds that the Company has not provided sufficient information on the environmental impacts of the proposed facilities at the alternative site with respect to air quality for the Siting Board to determine whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to air quality.

Accordingly, based on the foregoing, the Siting Board makes no finding as to whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to air quality.

In comparing the two sites, the record demonstrates that, where measured, existing background concentrations of criteria pollutants in the vicinity of the Edgar site are greater than 50 percent of the NAAQS. Further, assuming use of 0.3 percent oil, estimated concentrations with facility operation could exceed 60 percent of the NAAQS for all averaging periods for PM-10, SO_2 and NOx, and 90 percent of the standards for 24-hour SO_2, one-hour NOx, and annual PM-10 (See Table I).[216] Although there is no evidence in the record specifying the existing background concentrations and total future concentrations with facility operation at the Ironstone site, the record demonstrates that such concentrations would be lower than the primary site.

In comparing the air quality impacts at the two sites, the Siting Board disagrees with BECo that the key determinant is

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216/ With respect to annual averaging periods, the Company's estimates are based on oil use for the entire year. See n.99, above.

compliance with NAAQS. Where existing concentrations at one site already exceed 50 percent of NAAQS for criteria pollutants and facility operation could increase concentrations of certain pollutants above 90 percent of NAAQS, the margin of compliance must be considered in comparing the two sites. Thus, based on the Company's current analysis of air quality impacts, the Siting Board finds that the air quality impacts at the Edgar site would be greater than the air quality impacts at the Ironstone site.

The Siting Board recognizes that each of the Company's most recent fuel mix proposals would reduce impacts. As noted above in Section II.D.1.a.(1)(a), facility SO_2 and PM-10 impacts would be significantly reduced with increased use of natural gas and use of back-up fuel oil with reduced sulfur content. In addition, the emissions offset proposal has the potential to reduce overall emissions in the Edgar site vicinity. It is therefore possible that facility emissions would be reduced such that increases over background concentrations would be negligible or that overall air quality in the vicinity of the Edgar site would be improved. The Siting Board notes, however, that an emissions offset approach could be implemented at the Ironstone site. Thus, further reductions in air emissions impacts are equally likely to occur at either site.

In sum, the air quality impact analysis in the record demonstrates that construction of the proposed facility at the alternative site would be preferable to the primary site, with respect to air quality impacts.[217]

Accordingly, based on the foregoing, the Siting Board finds that the Ironstone site is preferable to the Edgar site with respect to air quality impacts.

217/ With regard to BECo's argument that the Edgar site would be preferable because the Ironstone site would require Rhode Island and Massachusetts permitting, the Siting Board notes that it does not consider multiple state permitting requirements in comparing the air quality impacts at two sites.

b. Surface Water Quality/Wetlands

(1) Description

The Company indicated potential impacts at the alternative site related to surface water quality and wetlands. With respect to surface water quality at the alternative site, the Company stated that the Blackstone River is only in marginal compliance with applicable water quality standards but that water quality is believed to have improved over the past 12 years (Exhs. BE-6, p. 5-30, UX-4, pp. 3-43, 3-44, HO-E-38). Although it has conducted no tests, the Company reported that it anticipated contamination in the form of high levels of chromium and PCBs (Exh. HO-E-38). BECo stated that this would be consistent with past industrial uses of the Blackstone River (Exh. UX-4, pp. 3-43). The Company indicated that in spite of possible high chromium and PCB levels, generating facility waste treatment systems could be designed, as at the primary site, to ensure that river water quality standards would not be violated (Exhs. BE-6, p. 5-30, HO-E-38, UX-7). The Company stated that the necessary water treatment technology to meet water quality discharge standards, including acceptable levels of chromium and PCBs, was readily available (Exhs. UX-7, UX-5, p. 37).

The Company also provided an analysis indicating that the water requirements of its proposed facility could be withdrawn from the Blackstone River consistent with criteria established under the Water Management Act (Exhs. HO-RR-84, HO-RR-78). (See G.L. c. 21G).[218] The Company indicated concern, however, that if the flow and quality of Blackstone River water was sufficiently marginal, that it might be necessary for the Company to restrict use of river water at the Ironstone site during

218/ The Company indicated that the proposed facility would require withdrawal of 3.6 cubic feet per second ("cfs") while the Water Management Act would allow withdrawal of up to 84 cfs (Exh. HO-RR-84). Low flow was calculated over a range from 67.9 cfs to 95.20 cfs (Exhs. HO-RR-66, HO-RR-78).

severe drought periods to protect water quality (Exh. BE-6, p. 5-30).

BECo stated that the Blackstone River does not provide habitat conditions which the Company expects to be suitable for any rare or endangered aquatic species (id. BE-6, p. 5-29). However, the Company indicated that the opportunity exists for sport fishing based on the types of species noted among the river population (id., pp. 5-29, 5-30). The Company also noted that two ponds exist on the alternative site property which provide a suitable habitat and could be stocked for sport fishing (id.).[219]

The Company reported that construction and operation of intake facilities at the alternative site would result in the same potential for impingement as is expected at the primary site, in proportion to the volume of water withdrawn (Tr. 21, pp. 32-36, Tr. 51, pp. 36, 40).[220] The Company indicated that, with the exception of the impacts on clamming, dredging at the alternative site intake would have comparable impacts on aquatic ecology to those at the primary site (id., p. 37).

The Company stated that there would be no hydrothermal impacts at the alternative site due to the installation of a closed loop cooling system with ambient air rather than water as a heat sink (Exh. BE-6, p. 5-31).

With respect to wetlands, the Company reported that two brooks and two small ponds had been identified within the approximately 300 acre site, but stated that no detailed wetlands delineation had been performed (id., pp. 5-10 to 5-11; Exhs. UX-22, UX-24, HO-RR-81). The Company indicated that, as a preliminary matter, it had located the footprint of the facility

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219/ The Company noted, that unlike the primary site, use of the alternative site is not expected to result in adverse impacts on clamming (Tr. 51, p. 36).

220/ The ratio of the volume of water withdrawn at the primary site to the volume of water withdrawn at the alternative site is 80:1 (Tr. 51, p. 40).

near the center of the site close to the existing gas pipeline and transmission right-of-way to avoid impacting brooks and ponds elsewhere on the alternative site (Exh. UX-23). The Company further stated that an initial review of USGS topographic maps and a land use map completed by the University of Massachusetts indicated the feasibility of constructing and operating a combined cycle generating facility at the alternative site without wetlands encroachment (Exh. HO-RR-81).

The Company identified ROW requirements for gas supply and electric interconnections, as well as water supply and effluent discharge lines between the alternative site and the Blackstone River (Exh. HO-RR-114). Although the Company did not estimate the extent of affected wetlands, the Company's analysis indicated ROW requirements would be 14 acres, and could be as much as 451 acres (id.). The Company's analysis further indicated that the ROW requirements would vary greatly depending on whether or not construction of a combined cycle generating facility at the alternative site precipitated the need for an additional Carpenter Hill-Millbury transmission line (id.). See Section II.E.1.c, below.

Uxbridge presented a number of arguments with respect to Boston Edison's analysis of surface water quality impacts at the alternative site (Uxbridge Initial Brief, p. 30). Uxbridge asserted that the Company relied almost exclusively on the Ocean State Power ("OSP") DEIS for its analysis of cumulative water impacts at the Ironstone site (id., p. 30, citing Tr. 21, pp. 43, 148, 149). Uxbridge further asserted that the Company did not supplement the information derived from the OSP DEIS with its own investigation or analysis in several critical areas, including the area of water quality (id., p. 32-33). Uxbridge contended that this failure to conduct needed supplemental analysis was made evident by the Company's responses during testimony (id., p. 33, citing Tr. 21, pp. 50, 55, 91, 97, 98). Similarly, Uxbridge argued, the responses provided by the Company during discovery examined the effect of water withdrawals on water quantity but not on water quality or aquatic life (id., p. 33; Exhs. UX-28, UX-6).

Uxbridge also noted that the Company, while considering the alternative site for an energy facility in 1984, had itself recommended that further analysis of the site was warranted with regard to water quality (Uxbridge Initial Brief, p. 36, citing Exh. UX-3, p. 1-6; Tr. 21, pp. 32-35). Uxbridge asserted that no such additional studies were performed (Uxbridge Initial Brief, p. 36). It therefore contended that the Company's water quality analysis was incomplete and deficient even by its own standards (id., citing Exh. UX-3, p. 1-6; Tr. 21, pp. 32-35).

With respect to wetlands, Uxbridge claimed that the Company's consideration of wetlands impacts at Ironstone was inadequate in several respects, including the failure to delineate wetlands and examine potential impacts of the facility on wetlands (Uxbridge Initial Brief, p. 36, citing Tr. 27, pp. 44-45; Exhs. UX-22, UX-23, UX-24; Tr. 22, pp. 36-37).

(2) Analysis

With respect to surface water quality, the Company has argued that generating facility waste treatment systems could be designed at the alternative site to ensure that river water quality standards would not be violated. The record indicates that applicable criteria would allow BECo to withdraw the 3.6 cfs of water required for the proposed facility from the Blackstone River. However, river flow and surface water quality is sufficiently marginal that BECo might need to limit its use of river water during severe drought periods. The Siting Board notes that OSP was required to adhere to minimum flow criteria. Here, the Company has not conducted any water quality analysis concerning the different flow levels of the Blackstone River.

Furthermore, we agree with Uxbridge that the Company's analysis of potential impacts at the Ironstone site is incomplete and inadequate in regard to water quality. In one previous review of a proposed 1.35 cfs wastewater effluent diversion for a generating facility in the Charles River basin, extensive analysis of stream flow, water quality and riverine ecology was provided to support the proposed diversion. See Enron, 23 DOMSC at 140-181. The Siting Board reiterates that all developers of proposed facilities are obligated to provide detailed information regarding the impacts of the proposed facility at both the primary and alternative site(s). Enron, 23 DOMSC at 212.

With respect to wetlands, the Company relied on the site observations of its witnesses and a land use map developed by the University of Massachusetts to support its position that it would be possible to site the proposed facility on the alternative site without encroaching on wetlands. However, the map does not appear to be focused on wetlands or other natural resources, and includes a limited number of relatively large wetlands. We agree with Uxbridge that the Company's delineation of wetlands and analysis of wetland impacts is not based on a detailed site investigation. In sum, the Company did not conduct an adequate analysis of water quality nor did it provide evidence to allow an evaluation of the likelihood of wetlands encroachment at the alternative site.

The Siting Board finds that the Company has not provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to surface water quality and wetlands for the Siting Board to determine whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to surface water quality and wetlands.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to surface water quality and wetlands.

In comparing the primary and alternative sites, the Company has argued that dredging impacts on aquatic ecology at the alternative site would be the same as those at the primary site. The Company has acknowledged, however, that the rate of withdrawal at the alternative site would be one-eightieth the rate at the primary site. A reduced rate of withdrawal at the alternative site suggests that less dredging for intake purposes may be required with proportionately less impact on aquatic ecology. Additionally, there would be no impact on shellfishing at the alternative site.

Further, with respect to impingement of fisheries, the record indicates that the potential for impingement at the intake structure at the alternative site would be the same as that at the primary site, in proportion to the volume of water withdrawn. Again, as the rate of withdrawal at the primary site would be eighty times that at the alternative site, the associated impacts on aquatic ecology at the primary site would be greater than those at the alternative site. In addition, the record indicates there would be no hydrothermal impacts at the alternative site due to the installation of a closed loop cooling system which would use ambient air rather than water as a heat sink.

Nevertheless, the record also demonstrates the potential for significant water quality impacts at the alternative site associated with low flow conditions on the Blackstone River. Further, the record indicates the potential for impacts to wetlands at the alternative site in excess of those at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that the primary site is preferable to the alternative site with respect to surface water quality and wetlands impacts.

c. Land Resources

(1) Description

BECo stated that the alternative site consists of approximately 300 acres, of which 20 to 25 acres would be cleared and used for the proposed facility (Exh. BE-6, p. 5-10; Tr. 55, p. 133). The Company also indicated that it expects that use of the alternative site would require approximately one mile of local road improvements (Exh. BE-48, AS-1, p. 10).[221]

BECo indicated that an additional area of approximately 426 acres would be required for new and expanded ROW in conjunction with siting the proposed facility at the alternative site (Exh. HO-RR-114). Specifically, BECo's estimates for these ROW's include four acres for the natural gas lateral pipeline, six acres for water supply and discharge, four acres for transmission interconnection, and an additional 412 acres for transmission reinforcement (id.).[222]

BECo stated that, based on its review of an aerial photograph of the alternative site, the areas that would be occupied by the natural gas pipeline and the electric power transmission interconnection are entirely wooded, and would therefore need to be cleared of existing trees (id.; Exh. BE-6, Fig. 5.6.3-1). The Company also claimed that areas adjacent to public ways which would be followed for the purpose of routing water supply and effluent lines are also heavily wooded, requiring tree clearing from these areas (Exh. HO-RR-114). BECo further stated that based on the rural nature of the towns traversed by the Millbury to Carpenter Hill 345 KV ROW, most of the 412 acres of land necessary to establish a new 345 KV circuit

221/ BECo provided a map indicating that the site could be accessed from State Route 146 by using a section of Elmwood Avenue, approximately one mile in length (Exh. BE-6, Fig. 5.6.2-1). BECo did not provide the Siting Board with an estimate for the width of any additional tree clearing necessary for local road improvements.

222/ BECo indicated that the proposed facility at the alternative site would be interconnected to BECo's transmission line 336, which extends between BECo's West Medway, MA substation and Eastern Utility Associates ("EUA") Sherman Road substation in Rhode Island (Exh. HO-RR-125). However, the Company indicated that the required transmission reinforcement would involve improvements on a different segment of the regional transmission system -- specifically, the addition of a new 17-mile 345 kV circuit extending between the Millbury, MA substation and the Charlton, MA substation (id.; Exh. HO-RR-114).

for transmission reinforcement -- as required for operation of the proposed facility at the alternative site -- would also need to be cleared of trees (id.).

Mr. Schmidt explained that cooling and process water would be obtained via a pipeline which would run from an intake structure located on the bank of the Blackstone River to the proposed facility (Tr. 32, p. 53-54). Mr. Schmidt further stated that no detailed pipeline routing had been developed (id.). Although estimating that six acres would be cleared for the water supply and effluent pipelines, BECo stated it would endeavor to follow public streets and ROW's as much as possible (id.; Exh. HO-RR-114). Dr. Morgenstern added that comparison of the impacts of cooling water facilities at the primary site and the alternative site was difficult because the actual intake location and pipeline route was not yet determined at the alternative site (Tr. 32, pp. 57-58).

With respect to transmission, BECo noted that the transmission reinforcement along the Millbury, MA to Charlton, MA ROW would be required with operation of the proposed facility at the alternative site, based on analyses of regional power flows (Exhs. HO-RR-124, HO-RR-125).[223] However, BECo stated that the transmission reinforcement may be required in the future to accommodate power flows on the regional transmission system, even without installation of the proposed facility at the alternative site (Tr. 56, pp. 151-152).

223/ BECo acknowledged that the transmission reinforcements which it claims are necessary between Millbury, MA and Carpenter Hill in Charlton, MA if the proposed facility is constructed at the alternative site, are identified as a planned transmission improvement on behalf of the Massachusetts Municipal Wholesale Electric Company in schedule 4 of the New England Power Pool 1992 Report on Capacity, Energy, Load and Transmission (Exh. HO-RR-124).

(2) Analysis

The Company's overall estimate of the extent of tree-clearing required for siting the proposed facility at the alternative site -- approximately 0.7 square mile -- is well above that identified for siting other generating facilities in previous Siting Council reviews.[224] We note, however, that based on BECo's analysis, most of the forestland displacement would occur as a result of clearing 412 acres for the transmission reinforcement between Millbury and Charlton.

As recognized by the Company, the transmission reinforcements could be required due to future load growth and/or future New England Power Pool ("NEPOOL") dispatching requirements, even if the proposed facility is not constructed at the alternative site. Thus, depending on when BECo might proceed with its project, installation of the proposed facility at the alternative site may or may not be the determining factor relating to need for the identified transmission reinforcement.

In addition, we note that the transmission reinforcement, if pursued, would be the subject of a separate Siting Board review. Such a review would include consideration of project alternatives, siting alternatives, design alternatives and other possible mitigation for the transmission reinforcement, any of which could significantly reduce the tree clearing requirement estimated by the Company. Thus, the importance of the transmission reinforcement's environmental impacts as part of the evaluation of the alternative site for the proposed facility are somewhat diminished.

Regarding BECo's estimate that six acres would be cleared for the water supply and effluent pipelines, the Siting Board notes that use of existing ROWs may reduce the area cleared. We

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224/ The largest estimate of total tree clearing requirements in a previous generating facility review was approximately 50 acres. EEC Compliance, 25 DOMSC at 350.

also note, however, that BECo expects use of the alternative site would require approximately one mile of local road improvements -- an additional factor that could result in tree clearing. Considering both the water supply/effluent pipeline ROW requirement and the local road improvement requirement, we conclude that it is reasonable to expect 25 feet of roadside tree clearing for a distance of at least a mile -- an area of three acres.[225] Therefore, for the purposes of this review, the Siting Board accepts an estimate of three to six acres of forestland displacement for purposes of local road improvements and installation of the water supply/effluent pipeline.

Thus, at a minimum, direct tree clearing requirements of between 31 and 39 acres would be required for construction of the proposed facility at the alternative site, including transmission interconnection, fuel supply, and water supply/effluent connections. Within that range, the Company would endeavor to minimize tree clearing for water supply/effluent pipelines by maximizing use of existing ROWs.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to land resources, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land resources.

The record demonstrates that the Company would implement facility design and mitigation measures that adequately ensure a minimum impact on the environment with respect to land resources.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the

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225/ The utility ROW out of the site to Elmwood Avenue and continuing along Elmwood Avenue represents over half of the likely water supply/effluent pipeline route.

alternative site would be minimized with respect to land resources.

In comparing the primary and alternative sites, the record indicates that the land resource impacts would be significantly greater at the alternative site, regardless of whether BECo's 412-acre estimate of necessary ROW expansion for the transmission reinforcement is included. With respect to the primary site, a permanent displacement of approximately 17 acres of forestland would occur as a result of the proposed 10.7-mile natural gas pipeline. However, no additional tree clearing would be required as a result of the construction and operation of the proposed facility at the primary site.[226] In contrast, the alternative site would require that between 31 and 39 acres be cleared and used for construction of the proposed facility, including the facility site and ROWs for the transmission interconnection, fuel supply, and water supply/effluent connections.

Accordingly, based on the foregoing, the Siting Board finds that the primary site is preferable to the alternative site with respect to land resource impacts.

d. Noise

(1) Description

BECo stated that it would limit the increase in noise from the proposed facility at the nearest residence to within 10 decibels above existing site area ambient sound levels by providing silencing equipment at major sources of facility noise (Exh. HO-E-62). Further, the Company stated that the size and wooded nature of the alternative site would provide a significant attenuating effect on noise impacts at the nearest residences (id.).

226/ Although, as previously noted by BECo, a total of 20 acres of forestland would be initially cleared along the entire length of the proposed natural gas pipeline route, 3.1 acres would be allowed to revegetate after construction is completed (Exh. HO-E-102, Resource Report 3, p. 10; Tr. 56, p. 135).

BECo stated that the alternative site is surrounded by a predominantly rural environment consisting of residential, agricultural and vacant areas with light traffic (Exh. BE-48, p. 22). The Company indicated that the nearest residence is located 1,460 feet from the center of the facility, on East Ironstone Road (Exhs. HO-RR-86, HO-RR-107). The Company stated that there are no stationary noise sources on or near the site, but noted that there is daytime noise from a quarry operation located to the east of the site (Exh. BE-49, p. 37).

The Company stated its noise analysis was based on background noise levels from the OSP FEIS, which BECo considered to be a good approximation of ambient sound levels in the vicinity of the alternative site (Exh. HO-RR-108).[227] BECo indicated that the highest predicted increase at Elmwood Avenue, a residential receptor located a distance of 1,760 feet from the center of the proposed facility, would be 6.0 decibels (id.). The Company also indicated that the highest predicted increase at the nearest property line, a distance of 1,000 feet, would be 9.1 decibels (Exhs. HO-RR-108 Rev.).

The Company stated that it would utilize mitigation methods for the alternative site similar to those proposed for the primary site (see Section II.D.1.d, above) (Tr. 54, p. 146).

(2) Analysis

The Company's noise attenuation estimates for the alternative site are based on a piecemeal analysis which includes some internal inconsistencies.[228] The Siting Board reiterates

227/ OSP is located in Burrillville, Rhode Island. The Company indicated that the close proximity of OSP and the similarity of surroundings are appropriate for use as ambient noise measurements (Exh. HO-RR-106). The Company had estimated the night time noise level at the alternative site to be 30 decibels, and found that the minimum noise levels at OSP were comparable (id., Exh. BE-48, p. 22).

228/ The Company stated that the closest residence was at East Ironstone Street. However, BECo based its noise analysis on a residence located approximately 300 feet further away on Elmwood Avenue. The increase at East Ironstone Street, the closest residential receptor, likely would fall somewhere between that all developers of proposed facilities are obligated to provide detailed information regarding the impacts of the proposed facility at both the primary and alternative site(s). Enron, 23 DOMSC at 212.

In regard to mitigation techniques for the alternative site, the Company indicated that it would incorporate mitigation methods on the order of those proposed for the primary site. The Siting Board notes, however, that the Company did not identify which mitigation would be considered and that the specific measures proposed for the primary site may not be the most effective measures for the alternative site.

Therefore, the Company has provided minimally sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to noise. The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to noise impacts, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to noise.

The record demonstrates that the Company would implement facility design and mitigation measures that would ensure a minimum impact on the environment with respect to noise impacts.

Accordingly, based on the foregoing, the Siting Board finds that with the implementation of mitigation measures, the environmental impacts of the proposed facility at the alternative site would be minimized with respect to noise impacts.

With respect to comparing the primary and alternative sites, the Company asserted that although MDEP guidelines could be met at either site, nighttime ambient noise levels surrounding the alternative site are lower than those surrounding the primary site, therefore the proposed facility would provide a better acoustical fit at the Edgar site (Exh. BE-48, p. 37; Tr. 54, p. 158).

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the 6.1 decibels estimated at Elmwood Avenue and 9.1 decibels estimated at the nearest property line to the site.

The Siting Board notes that the increase in noise levels at the residential receptors are similar for the primary and alternative sites. The Siting Board also notes that while the wooded nature of the alternative site would help buffer noise emissions to the nearest residences, the primary site would have a 60-foot wooded buffer adjacent to the nearest residence. Further, the Siting Board notes that mitigation techniques would be applied at either site. Therefore, based on the foregoing, the Siting Board finds that the primary site is comparable to the alternative site with respect to noise impacts.

e. Water Supply

(1) Description

The Company stated that it would obtain cooling and process water from the Blackstone River to operate the proposed facility at the alternative site (Exh. HO-RR-84). The Company indicated it would utilize 3.6 cubic feet per second ("cfs") of water, based on a nominal 300 MW combined cycle generating facility with closed cooling (id.). The Company stated that it would incorporate water demand reduction measures at the alternative site, similar to those at the primary site, including use of dry combusters and reuse of an average of 29,000 gpd of on-site stormwater runoff (Tr. 55, pp. 134-135).

The Company stated that adequate water would be available from the Blackstone River for the proposed project (Exh. HO-RR-84). In support, the Company presented an analysis indicating that, based on generally applicable criteria for ensuring minimum stream flow under the Water Management Act, M.G.L. c. 21G, a maximum of 84 cfs could be withdrawn at the expected alternative site intake location on the Blackstone River (id.). The Company noted the recent installation of the OSP project, which utilizes approximately 7 cfs from a downstream location on the Blackstone River, and stated that an adjustment for the OSP withdrawal still would result in a remainder of 77 cfs available for withdrawal consistent with Water Management Act criteria (id.).

With respect to possible conflict between required withdrawals for the alternative facilities and those for the existing OSP project, the Company provided information indicating that the OSP project is subject to permit conditions requiring that withdrawals be reduced or discontinued under certain circumstances when flow in the Blackstone River is less than 102 cfs (Exh. UX-85).[229] The Company also stated that the OSP project has no backup water supply, and therefore must cease operations if Blackstone River withdrawals are discontinued (Exh. HO-RR-85).

The Company asserts that the expected withdrawal of 3.6 cfs (2.3 mgd) from the Blackstone River for the alternative facilities would represent only a fraction of the amount of water available from the river under applicable state criteria (BECo Site Banking Brief, p. 20). However, the Company acknowledges that, based on the experience of Weymouth in unsuccessfully seeking approval under the Water Management Act to expand its water system to serve the proposed facilities at the primary site, as well as intervenor opposition to use of the alternative Ironstone site, some uncertainty must be accorded to the prospects of obtaining necessary approval to utilize the Blackstone River for facility water requirements (id., pp. 20-21). Therefore, the Company asserts that, based on the potential uncertainty of obtaining a water supply at the alternative site, in comparison with the certainty of the availability of the proposed or backup water supply plan at the primary site, the primary site is preferable to the alternative site (id., p. 22).

Uxbridge argues that the alternative site is not acceptable for the facility because the required water withdrawals would significantly and adversely affect the Blackstone River (Uxbridge Initial Brief, p. 40). Uxbridge's witness, Mr. Cohen, stated that the Blackstone basin contains a low proportion of stratified drift deposits, so that the river is subject to extreme drought

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229/ The Company indicated that since the OSP project went on-line, Blackstone River flow has dropped below 102 cfs on several occasions (Tr. 51, pp. 16-17). However, the Company cited newspaper accounts indicating that such flow conditions may have resulted from unauthorized flow interruptions by upstream dam owners, and concluded that the low flow conditions may not occur with the same frequency in future years (id., pp. 17-19).

conditions in periods of low rainfall (Exh. UX-66, p. 4-5). Uxbridge also argues that BECo has not analyzed the possibility of obtaining alternative water supply sources should it be unable to withdraw water from the Blackstone River (Uxbridge Initial Brief, p. 33).

(2) Analysis

The record demonstrates that the proposed withdrawal of 3.6 cfs from the Blackstone River for the proposed facilities at the alternative site would be consistent with generally applicable criteria under the Water Management Act. However, the Company acknowledges some uncertainty about its prospects for obtaining Water Management Act approval.

For a similar, albeit somewhat larger withdrawal at the downstream OSP project in Rhode Island, low flow withdrawal restrictions were deemed necessary by regulators. The Siting Board notes that, in its previous review of a proposed 1.35 cfs wastewater effluent diversion for a generating facility in the Charles River basin, extensive analysis of stream flow, water quality and riverine ecology was provided to support that proposed diversion. Enron, 23 DOMSC at 140-181. The Siting Board reiterates that all developers of proposed facilities are obligated to provide detailed information regarding the impacts of the proposed facility at both the primary and alternative site(s). Enron, 23 DOMSC at 212.

In addition to raising uncertainties with regard to low flow impacts on the river itself, the alternative site water supply raises the prospect of water use conflict with the downstream OSP project. Given the applicability of a low flow withdrawal restriction and the absence of a backup supply for the OSP project, any sizable upstream withdrawal for consumptive purposes would increase the potential for temporary OSP project shutdowns. In order to ensure that the potential for water use conflict would be minimized, additional information on existing and expected future stream flow, as well as any existing and possible additional arrangements for coordinating management of stream flows among major withdrawers and dam operators along the Blackstone River, would be necessary.

With respect to the level of water use, the Company has indicated its willingness to incorporate water use reduction measures corresponding to those at the primary site, including on-site stormwater reuse and use of dry combustor technology (see Section II.D.1.e., above). However, as discussed in the analysis of the primary site, the Company has identified design options which would allow the Company to reduce water requirements below the level assumed in its water supply analysis by an additional 351,000 gpd.

The Siting Board finds that the Company has not provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to water supply for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to water supply.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to water supply.

With respect to comparison of the primary and alternative sites, there are regulatory uncertainties and the long term potential for conflict with the interests of other water users at both sites. In addition, the Company's revised BACT analysis recommends use of 100 MW dry combustor designs that require substantially more water than the base dry combustor design, which the Company assumed in its analysis of the environmental impacts of the proposed facility with respect to water supply at both the primary and alternative sites.

However, the proposed and backup water supply plans at the primary site would rely on MWRA supply resources, which appear adequate to meet the needs of the proposed facility and existing water users until at least 2000 and possibly 2020. Further, the Company would need to comply, under its proposed water supply plan, with City of Quincy and MWRA water service connection requirements that appear to ensure some level of contribution by the Company to help maintain the integrity of system supplies. In contrast, the alternative site water supply would rely on withdrawals from the Blackstone River, resulting in potential water supply conflicts with the OSP project which could arise at any time after the proposed facility comes on-line. Further, the record identified no existing mechanisms for coordination among major river water users on the Blackstone River.

Accordingly, based on the foregoing, the Siting Board finds that the primary site is preferable to the alternative site with respect to water supply.

f. Land Use

(1) Description

BECo stated that the alternative site consists of over 300 acres, located in a rural setting (Exh. BE-6, pp. 5-10, 5-11). The Company indicated that the site consists of a second growth forest which comprises 84 percent of the site and agricultural lands which comprise 15 percent of the site area (Exhs. BE-6, p. 5-11, UX-56). BECo asserted that, based on the undeveloped character of the alternative site and the existing power generation development at the primary site, the proposed facility would have a significantly lesser land use impact if located at the primary site rather than at the alternative site (BECo Initial Brief, p. 204). However, the Company indicated that while power generation and operation at the alternative site would represent a change from the current use, no economic loss would result (Exh. BE-6, p. 5-32).

BECo stated the alternative site is bounded on the south by the Massachusetts/Rhode Island state line, on the north by a residential strip development along Elmwood Avenue and on the east by South Street (Exh. BE-6, p. 5-10). The Company stated that the western site boundary extends to within 800 feet of a residential development along Glendale Street (id.). The Company stated that surrounding land uses within a one-mile radius of the alternative site are approximately 65 percent vacant and 35 percent residential/agricultural (id., p. 5-11).

The Company indicated that the site is zoned for agricultural use, and that the surrounding land is also zoned as agricultural, with the exception of an area zoned for business and industrial to the east and northeast (id.). The Company noted that Uxbridge amended its Zoning By-laws in January 1989, to specifically prohibit the "commercial manufacture of electricity through the use of an electrical generating facility or cogeneration facility as a principal activity" in Uxbridge (id.). The Company stated that it would apply to the DPU to seek an exemption from local zoning requirements, thus addressing both regulatory zoning issues and the by-law amendment, on the grounds that the facility is needed to serve the public interest (Exh. HO-RR-57A, p. AS-2-3).

BECo indicated that ROW requirements would include interconnections to a 345 kV transmission line and a Tennessee pipeline located approximately 100 feet and 1,400 feet, respectively, from the northwest point of the alternative site (Exh. BE-6, p. 5-11). In addition, the Company asserted that it would have to undertake a 17-mile 345 kV electric transmission reinforcement project along existing ROW extending from Millbury to Charlton, Massachusetts (Tr. 56, p. 144). See Section II.E.1.c., above.

With respect to historic preservation, the Company noted that the site includes the Richardson Farm and a portion of the BRVNHC (Exh. UX-38). The Company asserted that the location of the facility at the primary site would have far less impact since locating the facility at the alternative site would have some degree of impact on historic and archeological resources (BECo Initial Brief, p. 214). However, the Company asserted that the alternative site does not contain any historical or cultural factors which would preclude the siting of the facility (id.). Further, the Company argued that Federal law establishing the BRVNHC does not prohibit power plants (id.).[230] BECo noted

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230/ Public Law 99-647 created the BRVNHC to preserve the unique and significant contributions to the national heritage of certain historic and cultural lands, waterways and structures within the Blackstone River Valley (Exh. UX-38, p. 2).

that the Richardson Farm is not located in a historic district, nor is it listed on the Register of Historic Places (Tr. 28, pp. 61-62). Uxbridge's witness, Mr. Pepper, stated that the site contains an old Georgian Farmhouse, an active sawmill, and several other old, but actively used buildings (Exh. UX-38, p. 4). Mr. Pepper also stated that approximately 245 acres of the site are classified as active forest land and 25 acres are classified as active farmland (id.)

Mr. Pepper raised concerns about the effects on the nationally significant character of the Blackstone River Valley, and stated Uxbridge's opposition to building the facility without additional information from the Company (Tr. 28, p. 54). Mr. Pepper stated that the Company has not addressed pertinent national policies or the consistency questions concerning the historic nature of the Richardson Farm and the Blackstone River Valley (id., p. 84). Mr. Pepper admitted that neither the BRVNHC Commission nor anyone else, had yet ascertained the historic value of the Richardson Farm, but he maintained that the BRVNHC Commission believes that it is potentially historically significant (id., pp. 63, 95). Pointing to the recognition by the Company that the site is located in a national heritage corridor, Mr. Pepper emphasized the failure of the Company to analyze how the proposed facility would impact the site (id., p. 100).

Finally, Uxbridge argued that BECo did not analyze the overall impact that construction at the alternative site would have on historic preservation (Uxbridge Initial Brief, p. 34).

(2) Analysis

The record demonstrates that the development of the alternative site would alter presently undisturbed forested and agricultural lands. However, the Siting Board recognizes that the size of the alternative site would present opportunities to buffer the proposed facility from surrounding land uses. Further, the Siting Board notes that the site is presently zoned for agricultural use and that the By-Laws of Uxbridge prohibit the construction of generation facilities in Uxbridge. However, the Siting Board agrees with the Company that the Town of Uxbridge By-law amendment prohibiting generating facilities should not be a deciding regulatory factor. The Company could seek zoning variances or exemptions from the appropriate agencies.

While we recognize the importance of the BRVNHC and the federally authorized efforts to protect the Blackstone River Valley, we cannot conclude that the alternative site is a historical and cultural land which the BRVNHC Commission was designed to protect. In fact, the alternative site would not displace historically significant features, and mitigation of visual and other impacts could preserve any unique features of the alternative site.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to land use, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to land use.

The record demonstrates that the Company would implement the facility design and mitigation measures that adequately ensure a minimum impact on the environment with respect to land use.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land use.

In comparing the primary and alternative sites, based on the undeveloped character of the alternative site and the existing power generation development at the primary site, the Siting Board finds that the primary site is preferable to the alternative site with respect to land use.

g. Visual Impacts

BECo stated that the proposed facility would be only moderately visible to areas surrounding the alternative site, with potential screening (Exhs. BE-6, p. 5-33; BE-48, p. 39). BECo further stated that due to the good landscape quality at the alternate site, the proposed facility would result in a moderate degree of change in visual quality (id.).

The Company stated that existing trees would heavily screen views of the proposed facility at the alternative site (Tr. 22, p. 18-21; Tr. 23, p. 9). The Company provided photographs of a balloon at an elevation of 250 feet to simulate the likely visibility of the stack from nine locations near the alternative site (Exh. HO-RR-44).[231] The photographs showed that viewers would see a significant portion of the stacks from one location -- a section of South Street (id., Plate 7). In addition, the Company stated that there would be views of the proposed facility from some portions of Route 146 to the east of the alternative site (Tr. 22, pp. 18-19).

The Company stated that despite the fact that the alternative site and surrounding area is heavily treed providing good screening, any views of the proposed facility would be an extreme change from the current viewshed (Tr. 22, p. 23).

BECo asserted that the proposed facility would have a less severe visual impact at the primary site than at the alternative site (BECo Initial Brief, p. 205). The Company explained that, although the proposed facility would be more visible at the primary site than at the alternative site, it would be visually compatible at the primary site and visually incompatible at the alternative site (Exhs. BE-6, p. 7-24, BE-59, p. 6.7-2; Tr. 22, p. 23).

The Company has shown that the visibility of the proposed facility at the alternative site would be limited given the size

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231/ The photographs were taken from the following locations: (1) in front of the Richardson farmhouse on East Ironstone Road, (2) behind the Richardson farmhouse approximately 250 feet from East Ironstone Road, (3) King Street approximately 1000 feet west of Glendale Street, (4) King Street approximately 2000 feet west of Glendale Street, (5) the intersection at Glendale Street and Elmwood Avenue, (6) South Street approximately 2000 feet north of East Ironstone Road, (7) South Street approximately 1300 feet north of east Ironstone Road, (8) King Street approximately 1500 feet north of the Douglas Pike, and (9) the Douglas Pike approximately 500 feet west of the King Street intersection (Exh. HO-RR-44).

of the site and the natural buffer of trees. Nonetheless, the two 245-foot high, 17-foot diameter stacks would be visible from some locations and would represent a significant change in the otherwise largely rural landscape. The Siting Board also notes that the visibility of the proposed facility at the alternative site, although limited based on the Company's photographs, likely would be greater during leaf-off conditions in the fall and winter.

Despite the possibility of significant visual changes in some locations, the record demonstrates that the proposed facilities would not have a major overall visual impact at the alternative site.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to visual impacts, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to visual impacts.

The record demonstrates that the Company would implement facility design and mitigation measures that ensure a minimum impact on the environment with respect to visual impacts.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to visual impacts.

In comparing the proposed and alternative sites, BECo's analysis shows that location of the proposed facility at the primary site is likely to involve greater visibility than at the alternative site. In contrast to the rural nature of the alternative site, however, the industrial nature of the viewshed at the primary site would minimize the incremental visual impacts of the proposed facility at the primary site. Additionally, existing screening and BECo's proposed mitigation would further minimize visual impacts at the primary site. Therefore, the proposed facility would have a greater net impact on visual resources at the alternative site than at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that the primary site is preferable to the alternative site with respect to visual impacts.

h. Traffic

The Company indicated that the alternative site is bordered on the south by the Massachusetts/Rhode Island state line and Elmwood Avenue, South Street and Glendale Avenue to the north, east and west, respectively, all single lane secondary roadways containing residential development (Exh. BE-48, AS-1, p. 10). The Company stated that the likely route of site access would be Interstate Highway 495 to State Route 16, then eleven miles west along State Route 16, four miles south along State Route 146 and one mile west along Elmwood Avenue (id.). The Company noted that construction of the proposed facility at the alternative site would require improvement of approximately one mile of local off-site roadway (id., p. 31).

The Siting Board notes that the Company did not provide a description of the existing and estimated future traffic flow on any of the roadways leading to the alternative site or analyze potential impacts to traffic resulting from construction and operation of the proposed facility at the alternative site. Here again, the Company has failed to provide adequate analysis for the Siting Board to determine whether or not impacts would be adequately minimized at the alternative site. The Siting Board reiterates that all developers of proposed facilities are obligated to provide detailed information regarding the impacts of the proposed facility at both the primary and alternative site(s). Enron, 23 DOMSC at 212.

The Siting Board finds that the Company has not provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to traffic impacts for the Siting Board to determine whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to traffic impacts.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site have not been minimized with respect to traffic.

In comparing the primary and alternative sites, the Siting Board notes that barge delivery of most of the heavy equipment, which would minimize truck deliveries to the primary site, would not be an option at the alternative site. Thus, construction at the alternative site would require a greater number of truck deliveries than would construction at the primary site and would have a greater potential to impact local traffic. Additionally, construction of the necessary improvements to Elmwood Avenue would, itself, cause some traffic disruption. Accordingly, based on the foregoing, the Siting Board finds that construction of the proposed facility at the primary site would be preferable to construction at the alternative site with respect to traffic impacts.

i. <u>Safety</u>

With respect to existing site conditions at the alternative site, the Company indicated that the site has been used for farming for at least 200 years and that it was not aware of any contamination problems at the site (Tr. 53, pp. 120-121). However, the Company noted that no hazardous waste investigations had been performed at the alternative site (Exh. HO-E-35). The Company further stated that required clearing of the construction areas at the alternative site also would be performed by mechanical means rather than by the use of herbicides (Exh. HO-E-36).

With respect to transport and storage of hazardous materials, the Company indicated that the same safety considerations that would be incorporated into facility design and operation at the primary site, including enclosure of ammonia tanks, would be incorporated into facility design and operation at the alternative site (Exhs. HO-E-74, HO-E-75, HO-RR-119). Finally, the Company stated that the fire protection system would be essentially the same at both sites (Exh. HO-E-37).

The record demonstrates that there are no apparent contamination problems at the alternative site but that no investigation of the soil and groundwater has been conducted. The Siting Council notes however, that, due to the farming use of the property for the past 200 years, it is unlikely that significant contamination, as that found on an industrial site, would exist at the alternative site. The record further demonstrates that safety considerations in the design and operation of the proposed facility would be the same at both sites.

The Siting Board finds that the Company has provided minimally sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to safety, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to safety.

The record demonstrates that the Company would implement facility design and mitigation measures that ensure a minimum impact on the environment with respect to safety.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to safety.

In comparing the primary and alternative sites with regard to safety impacts, the Siting Board notes that, although it has found that the safety impacts can be adequately minimized at both sites, safety concerns differ at the two sites due to existing site conditions, and would be greater at the primary site. Subsurface soil and groundwater contamination, due to previous industrial uses, has been documented at the primary site, while contamination, to the same extent, would be unlikely at the alternative site. Construction and operation of the proposed facility could likely proceed at the alternative site without the site remediation requirements and worker protection precautions that would be required at the primary site.

Accordingly, based on the foregoing, the Siting Board finds that construction of the proposed facility at the alternative site is preferable to the primary site with respect to safety impacts.

j. Electric and Magnetic Fields

BECo indicated that the electrical power output from the proposed facility at the alternative site would be supplied to the area power system at BECo ROW 13 via a double circuit overhead transmission line interconnect approximately 1300 feet in length (Exh. HO-E-64).[232]

BECo provided the Siting Board with calculations of 60 Hertz EMF levels along the edges of its ROW 13, both northeasterly and southwesterly of the proposed tap, based on: (1) horizontal and vertical dimensional coordinates at the center of the transmission line span; (2) conductor size; and (3) net ampere loading for the individual conductors (id.). The Company's analysis indicated that, at an output level of 300 MW, the highest electric field would be 1.246 kV per meter, and that the highest magnetic field would be approximately 48 milligauss.[233]

BECo stated that it has no programs presently underway to reduce EMF on existing transmission lines, and that future mitigation programs would be dependent upon on-going research and debate concerning actual limits on exposure to magnetic fields (Exh. HO-RR-116).[234] BECo acknowledged the existence of

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232/ BECo indicated that it would extend a 345 KV loop from BECo transmission line 336 on ROW 13 to the Ironstone site and back to ROW 13 by utilizing a double circuit pole (Exh. HO-E-64). After rejoining ROW 13, the loop line would extend southwesterly, parallelling existing transmission lines for approximately 1.5 miles to the Sherman Road substation (Tr. 56, p. 144).

233/ See Table 2 for complete data regarding the Company's calculations of EMF levels for the alternative site.

234/ The Siting Board notes that BECo's existing transmission lines are not ancillary facilities as defined in G.L. c. 164, § 69G. However, in order to allow comprehensive analysis and comparison of environmental impacts of the proposed and alternative generating facilities, the Siting Board may address any potentially significant effects of such facilities on EMF levels along existing transmission lines.

several industry practices utilized to mitigate EMF on transmission lines, such as the use of particular line configurations, phase spacing, and rolling of phases on adjacent circuits (id.).

In a previous review of proposed transmission facilities which included 345 kV transmission lines, the Siting Board accepted edge of right-of-way levels of 1.8 kV/meter for the electric field, and 85 milligauss for the magnetic field. 1985 MECo Decision, 13 DOMSC at 119, 228-242. Here, the Siting Board notes that the edge of ROW EMF levels associated with the alternative Ironstone site (345 kV transmission system) are well below the levels found acceptable in the 1985 MECo decision.

Nevertheless, the Siting Board expects that BECo would implement phase arrangements and/or extend all reasonable efforts to utilize any other known mitigation techniques to minimize EMF levels along its loop line as well as along affected existing transmission lines.

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the proposed facility at the alternative site with respect to EMF, including adequate consideration of facility design and mitigation measures, for the Siting Board to determine whether the environmental impacts of the proposed facility would be minimized with respect to EMF.

The record demonstrates that the Company's construction plans, including possible future use of reasonable measures to minimize EMF impacts on portions of the existing transmission system affected by the proposed facility, adequately ensure a minimum impact on the environment with respect to EMF.

Accordingly, based on the foregoing, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to EMF.

In comparing BECo's calculated edge of ROW EMF levels at the primary and alternative site, the Siting Board notes that both analyses demonstrate that EMF levels would be well below the levels accepted in the 1985 MECo Decision, both for the existing 115 kV transmission lines serving the primary site, and the proposed 345 kV transmission line interconnect at the alternative site. However, in comparing the Company's EMF data (see Table 2, attached), regarding predicted EMF levels at the primary and alternative sites, the Siting Board finds that, based on the foregoing, the primary site is preferable to the alternative site with respect to EMF impacts.

2. Cost of the Proposed Facilities at the Alternative Site

In this section, the Siting Board evaluates whether the Company has provided sufficient information to allow the Siting Board to determine if the Company has achieved the appropriate balance among 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.

With respect to direct capital cost at the Ironstone site, the Company estimated total costs of materials and labor at $246,032,768, including: $19,256,353 for site acquisition, site work, structures, yard and building services; $32,755,000 for the heat recovery system generator and appurtenances; $103,131,000 for the steam turbine and combustion turbine generator sets; $38,495,812 for plant systems and equipment; $36,807,303 for transmission interconnection; $1,231,000 for start-up and testing; and $14,188,300 for scope additions and additional investments and improvements (Exhs. HO-RR-120, Table AS-5-2, HO-RR-57A, p. AS-5-9; Tr. 58, pp. 141-143). The Company indicated that its overall direct cost estimate includes a total labor cost of $32,858,600 (Exh. HO-RR-57A, p. AS-5-9).

The Company asserted that the Edgar site is preferable to the Ironstone site with respect to cost, noting that the lower cost at the Edgar site was principally accounted for by two cost components, site procurement cost and transmission reinforcement costs (BECo Site Banking Brief, p. 29; Exhs. HO-RR-120, HO-RR-121). The Company noted the difference in costs relative to the primary site also reflect overall labor costs[235] and costs for: (1) site procurement, (2) site preparation and foundations, (3) heat rejection system components, (4) electric power transmission, (5) fuel handling, and (6) municipal improvements (Exh. HO-RR-121, Table AS-5-1). See Table 4, attached.

The Company estimated a cost of approximately $8,756,457 for procurement of the Ironstone site, as compared with a zero cost for site acquisition at the primary site (Exh. HO-RR-121, Table 1). However, the Company estimated that foundations at the alternative site would cost $1,074,000 less than at the primary site, assuming use of a shallow spread footing foundation system without soil densification at the Ironstone site (Exhs. BE-6, p. 5-25, HO-RR-57A, p. AS-5-5, Table AS-5-3).

With respect to heat rejection costs, the Company indicated that a closed-cycle cooling system would be utilized at the Ironstone site (Exh. HO-RR-57A, p. AS-5-5). Based on a figure developed by Stone and Webster and verified by UE&C, the Company estimated a cost of $8,006,104 for major cooling system components (Exh. HO-RR-57A, p. AS-5-5, HO-RR-121, Table 1).

The Company estimated a cost of $36,807,303 for transmission improvements at the alternative site, $31,769,942 more than at the primary site (Exhs. HO-RR-57A, p. AS-5-6, AS-5-7, Exh. HO-RR-121, Table 1). The Company reported that, of the aforementioned $36,807,303, $27,264,668 represents estimated costs for substantial transmission improvements which would be required along a 17-mile segment of the Millbury-Carpenter Hill transmission line (Exhs. HO-RR-57A, pp. AS-5-6, AS-5-7, HO-RR-123, HO-RR-124). With respect to fuel handling, the Company estimated costs of $11,929,708 at the Ironstone site, as compared to $6,882,000 at the Edgar site (Exh. HO-RR-120, Table AS-5-2).

235/ Specifically the Company indicated that the estimated direct labor costs of $32,858,600 for the alternative site would be $4,553,000 less than that for the Edgar site (Exh. HO-RR-57A, pp. AS-5-8, AS-5-9).

With respect to municipal improvements, the Company estimated a zero cost at the Ironstone site, as compared to $2,400,000 at the primary site (id.; Exh. HO-RR-121, Table 1). The Company noted, however, that additional municipal improvements would likely be required at the Ironstone site if local approval were sought (Exh. HO-RR-57A, p. AS-5-8).[236] The Company asserted that any extra costs for municipal improvements at the Ironstone site would only increase the already significant advantage of the Edgar site against the Ironstone alternative with regard to cost (BECo Site Banking Brief, p. 28).

With respect to operating costs at the alternative site, the Company estimated NPV life cycle gas supply costs of $1,191,390,741 (Exh. HO-RR-121, Table 4).[237] The Company noted that use of the Ironstone site would require less gas pipeline construction than use of the primary site, reducing gas supply costs (Exh. HO-RR-57A, p. AS-5-11, AS-5-12). However, the Company stated that the Edgar site allows greater fuel efficiency based on use of the once-through cooling system, as compared to the closed-cycle cooling system at Ironstone (Exh. HO-RR-57A, pp. AS-5-12, AS-5-13). In addition, the Company stated that the closed-cycle cooling system at the Ironstone site would result in an incremental capability cost advantage for the Edgar site, reflecting differences in internal pumping requirements (Exh. HO-RR-57A, p. AS-5-13).[238] The Company estimated a net NPV operating cost advantage of $8,746,178 for the Edgar site,

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236/ The Company also noted that more detailed engineering and site assessment had been performed for the Edgar site than the Ironstone site and that comparable analysis for the Ironstone site would likely identify site work and costs beyond those already tabulated (Exh. HO-RR-57A, p. AS-5-8).

237/ With LDC cost sharing of certain capital costs, the Company estimated its share of life cycle gas supply costs at Ironstone as $1,120,374,006 (Exh. HO-RR-121, Table AS 5-11).

238/ The Company explained that power generated is used internally to drive closed cooling system equipment components, affecting the amount of power available for sale (Exh. HO-RR-57A, p. AS-5-13).

considering together the differences in life cycle gas costs and incremental capability costs (Exh. HO-RR-121, Table 1).[239]

With respect to water supply costs, the Company indicated that there would be no water purchase costs at the Ironstone site compared to $4,761,175 at the Edgar site (Exh. HO-RR-122).[240] However, the Company estimated a 1994-2013 NPV cost of $4,036,836 for water treatment at the Ironstone site, $922,076 greater than at the Edgar site (id.).

The Company has provided estimates of the overall costs of the proposed facility at the alternative site, as well as components of capital and operation costs which are site dependent. The Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility at the alternative site to allow the Siting Board to determine 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 cost advantage of $40,854,241 for the Edgar site over the Ironstone site, including a $35,947,162 capital cost advantage and a $4,907,079 NPV operating cost advantage (Exh. HO-RR-121, Table 1).

However, the Company provided oil storage for 45 days of oil-fired generation, based on LDC cost-sharing at Ironstone 2(Exh. HO-RR-57A, p. AS-5-11). The Siting Board notes that with

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239/ This figure balances an advantage of $27,436,615 in NPV life cycle gas costs at the Ironstone site against an advantage of $36,182,793 in NPV incremental capability costs at the Edgar site (Exhs. HO-RR-121-1, Table HO-RR-121-1, HO-RR-57A, Table AS-5-12).

240/ Incorporating either of the Company's two preferred BACT options would increase water supply requirements of the proposed facilities at either site. Consequently, associated water costs at the primary site would also increase. However, with either BACT option, the increase in water supply needs would less than double. (See Section II.D.1.e). Thus while water supply costs at the primary site would likely increase under either BACT option, the Siting Board notes that such costs would double at the most and would more probably be lower.

365 days of gas-fired operation an option under consideration, costs for oil storage tank construction at the Ironstone site, presently calculated at $5,047,708, could be considerably reduced if not avoided altogether (Tr. 57, p. 112). Eliminating the cost of oil storage tank construction at Ironstone would reduce the total cost advantage at the Edgar site to $35,806,533.

The Siting Board also notes that the Company assumed a $27,264,668 expenditure for 17 miles of transmission improvements along the Millbury-Carpenter Hill line (Exh. HO-RR-57A, Table AS 5-5). The Company acknowledged, however, that the Millbury-Carpenter Hill transmission improvements might be required at some date in the future to accommodate power flows on the regional transmission system, even without installation of the proposed facilities at the alternative site (Tr. 56, pp. 148-152). (See Section II.E.1.c.(1) above). Thus it is uncertain that the $27,264,668 expenditure for these transmission reinforcements would be required for siting of the proposed facility in Uxbridge. Eliminating the cost for transmission reinforcements on the Millbury-Carpenter Hill line would further reduce the total cost advantage of the Edgar site over the Ironstone site to $8,541,865.

Based on the above, the Siting Board finds that the Company has demonstrated that the cost of constructing and operating the proposed facility at the primary site would be less than the cost at the alternative site, even in the event that transmission reinforcements along the Millbury-Carpenter Hill line are not required in conjunction with use of the alternative site.

Accordingly, the Siting Board finds that construction of the proposed facility at the primary site is preferable to construction of the proposed facility at the alternative site with respect to cost.

3. Conclusions on the Proposed Facilities at the Alternative Site and Site Comparison

In this section, we review the consistency of the proposed facility at the alternative site with our overall review standard, requiring that an appropriate balance be achieved among environmental impacts and costs. Such balancing includes trade-offs between conflicting environmental impacts as well as trade-offs between respective environmental impacts and cost.

The Siting Board has found that, based on the implementation of the facility design and mitigation specified in Section II.E.1 above, the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land resources, noise, land use, visual impacts, safety, and EMF.

Further, the Siting Board has found that the Company did not establish that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to surface water quality/wetlands, water supply, and traffic. The Siting Board made no finding regarding whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to air quality.

Finally, the Siting Board has found that the Company provided sufficient information on the costs of the proposed facility at the alternative site to allow the Siting Board to determine whether an appropriate balance would be achieved among environmental impacts and cost.

The record indicates that there are no significant issues involving the balance among land resources, noise, land use, visual impacts, safety and EMF, nor between any of these concerns and air quality, water supply, water quality/wetlands or cost. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would be minimized with respect to land resources, noise, land use, visual impacts, safety and EMF, consistent with minimizing cost and other environmental impacts.

As discussed in Section II.E.1.h above, the Company failed to provide an analysis of traffic impacts and related mitigation for either the construction or operation of the proposed facility at the alternative site. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility at the alternative site would not be minimized with respect to traffic, consistent with minimizing cost and other environmental impacts.

To complete its review, the Siting Board must address whether environmental impacts with respect to each of the remaining issues -- air quality, surface water quality/wetlands, water supply -- would be minimized, consistent with minimizing cost. The Company's analyses as discussed in Sections II.E.1.a., II.E.1.b., and II.E.1.e., suggest that trade-offs among air quality, surface water quality and water supply are a factor, as well as trade-offs between the respective environmental concerns and cost. Therefore, the Siting Board must address the balance among air quality, surface water quality/wetlands, and water supply.

In Section II.D.3 above, regarding the primary site, the Siting Board addressed the three-way trade-off among air quality, water supply and cost, based on the Company's analysis of air emissions, water requirements, and costs under alternative combustor and fuel mix designs. The trade-offs between air emissions and costs at the alternative site would correspond to those at the primary site, although the net emissions under the emissions offset proposal could differ. With respect to water supply, the Company's proposed reliance on the Blackstone River for its water supply requirements at the alternative site, although apparently consistent with Water Management Act criteria, could affect long-term competition among water users, involving trade-off issues similar to those raised by the Company's proposed reliance on limited MWRA supplies for its process water requirements at the primary site.

Thus, for the same reasons set forth in Section II.D.3 above regarding the primary site, the Siting Board makes no findings as to whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to air quality, consistent with minimizing costs and other environmental impacts. Similarly, the Siting Council makes no findings as to whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to water supply, consistent with minimizing costs and other environmental impacts.

In addition to potentially affecting competing users of water from the Blackstone River, the water requirements of the proposed facility at the alternative site could affect the water quality and riverine ecology of the Blackstone River. Thus, there are potential trade-offs between surface water quality and both air quality and cost, similar to the trade-offs between water supply and both air quality and cost.

As discussed in Section II.E.1.e.(2) above, the Company failed to provide any analysis of the possible impacts of its proposed water withdrawals from the Blackstone River on surface water quality, or on riverine ecology as affected by water quality. Without such analyses, the Company is unable to establish the basis by which it determines the appropriate level of power augmentation and associated water requirements at the alternative site, assuming use of the dry combustor technology consistent with the Company's proposed facility designs.

Accordingly, the Siting Board makes no findings as to whether the environmental impacts of the proposed facility at the alternative site would be minimized with respect to surface water quality/wetlands, consistent with minimizing costs and other environmental impacts.

With respect to the comparison of the primary and alternative sites, the Siting Council has found: (1) that the primary site is preferable to the alternative site with respect to surface water quality, land resources, water supply, land use, visual impacts, traffic, and EMF; (2) that the primary and alternative sites are comparable with respect to noise; and (3) that the alternative site is preferable to the primary site with respect to air quality and safety.

The primary site was found to be preferable with respect to the majority of environmental issues. Most notably, the primary site was clearly preferable with respect to surface water quality/wetlands and land resources, given that the primary site is already transformed for utility purposes, while use of the alternative site would require transforming a natural, wooded area and also potentially contribute to a need to clear up to 412 acres for transmission reinforcements.

Although the alternative site was found to be preferable with respect to air quality, we note that this finding was based on differences in existing background conditions at the two sites, not on the extent of expected facility emissions at the primary site. In fact, the expected facility emissions under the natural gas proposal would be well below those reflected in the Company's ambient air quality modelling analysis, which nonetheless shows compliance with all applicable standards. Moreover, the apparent justification for further pursuit of the emission offset proposal by the Company is that net area emissions would be even less than those under the natural gas proposal. Thus, the preferability of the alternative site with respect to air quality is a limited one.

Based on the foregoing, the Siting Board finds that the primary site is preferable to the alternative site with respect to environmental impacts.

The Siting Board has found that the primary site is preferable to the alternative site with respect to cost.

Accordingly, the Siting Board finds that the primary site is superior to the alternative site.

III. DECISION

The Energy Facilities Siting Board hereby CONDITIONALLY APPROVES Boston Edison Company's primary site in Weymouth, Massachusetts for possible, future use as a site for a 306 megawatt, gas-fired, bulk electric generating facility and ancillary facilities. The CONDITIONS set forth in this decision are as follows.

(A) In order to address minimization of CO_2 emissions in the final petition, the Company shall include in its final petition, (1) a proposal to comprehensively address the CO_2 emissions from the proposed facility, and (2) 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 adequately considered.

(B) The Company shall provide its share of funding for the preparation of the health study, in a manner consistent with the agreement between BECo and Weymouth, except that BECo shall provide a sufficient portion of such funding in an earlier payment or series of payments, as may be further agreed by BECo and Weymouth, to allow the health study to proceed according to a reasonable schedule beginning at the time BECo files its final petition for construction of the proposed facilities with the Siting Board.

(C) In order to demonstrate that impacts to community noise levels are minimized, BECo shall: (1) incorporate all proposed mitigation techniques as described in Section II.D.1.d., above, so that the continuous noise increase from the operation of the proposed facility is no more than five decibels; (2) refrain from conducting construction that generates significant noise before 8:00 am; and (3) confine all primary construction activity to between the hours of 6:30 a.m. and 4:45 p.m. Monday through Saturday; except as necessary for structural integrity or safety reasons; and

(4) if issued a noise citation by the Weymouth Board of Health or MDEP, promptly investigate the potential source of cited noise and, as necessary, provide temporary sound barriers or implement other appropriate measures to mitigate such noise.

(D) In order to demonstrate that land use impacts are minimized, BECo shall: (1) provide the Siting Board with copies of either a zoning exemption from the DPU or a zoning variance from Weymouth (or special permit from Weymouth, whichever is applicable), indicating that the generating facility can be constructed in said location, and (2) construct, operate and maintain a waterfront park along King's Cove for use by the public. Specific details of the park area, layout, construction methods and materials shall be reviewed and coordinated with Weymouth's Waterfront Committee.

(E) In order to demonstrate that the traffic impacts are minimized, BECo shall implement its proposed traffic mitigation strategies during the construction of the proposed facility, including (1) the scheduling of the construction work force arrival/departure times outside the morning and afternoon commuter peak hours of 7:30 am to 8:30 am and 4:45 pm to 5:45 pm; (2) the institution of turning restrictions to and from Route 3A from site driveways; and (3) the control of traffic exiting the site during peak afternoon traffic hours, as needed.

(F) The Company shall submit written confirmation from the Weymouth Board of Health that the existing Edgar generating station has been enclosed in accordance with its recommendations at the time the Company submits its final application.

(G) The Company shall provide for Weymouth participation in the development of its Emergency Response Plan and for review of the Plan by appropriate local agencies, prior to construction and periodically during operation of the proposed facility.

(H) The Company shall provide for the review of its plans for the storage, containment and transport of aqueous ammonia by the Weymouth Emergency Planning Committee.

(I) The Company shall review its plans for maintaining an adequate supply of water for fire fighting purposes with the Fire Department, prior to construction of the proposed facility, and to revise plans, as necessary, to address any concerns raised by the Weymouth Fire Department.

The Siting Board notes that all findings in this decision are subject to modification based upon new information such as significant changes in the project, site conditions, applicable law or relevant technology and science. The Siting Board also notes that the Company is required to submit another filing with the Siting Board before its proposed project can be constructed. At that time, the Siting Board will review all new facts and information, including a complete analysis of air quality impacts and water supply issues and related costs as discussed herein, as well as significant changes that have occurred which would modify any of the findings contained herein.

In addition to the review of any changes in project design, site conditions, applicable law, or other relevant facts, and a showing that all conditions specified herein are addressed, final approval of the Edgar project will require a showing of need on reliability or economic efficiency grounds. The Company will also have to compare its proposed project with other energy resource alternatives, and establish that the project is viable.

Further, the Siting Board will conduct its final balancing of need, cost and environmental impacts before a final decision on the project is made.

Robert W. Ritchie

Robert W. Ritchie
Hearing Officer

Dated this 5th day of August, 1993

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of August 5, 1993 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, ESFB/DPU); Barbara Kates-Garnick (Commissioner, DPU); Mary Clark Webster (Commissioner, DPU); Robert Levite (for Stephen Tocco, Secretary of Economic Affairs); Andrew Greene (for Trudy Coxe, Secretary of Environmental Affairs); Joseph Faherty (Public Member); William Sargent (Public Member).

Kenneth Gordon
Chairman

Dated this 5th day of August, 1993

TABLE I

PREDICTED MAXIMUM AMBIENT CONCENTRATIONS AND AMBIENT STANDARDS

Pollutant	Averaging Period	Facility Emissions	Background Concentrations	Total Concentrations	NAAQS	Background % of NAAQS	Total % of NAAQS
PM-10	Annual	3.63	42.00	45.63	50	84.00	91.26
	24-Hour	41.40	91.00	132.40	150	60.67	68.73
SO_2	Annual	7.88	59.95	68.83	80	74.94	86.04
	24-Hour	83.90	273.20	357.10	365	74.85	98.05
	3-Hour	136.00	678.00	814.00	13,000	52.15	62.62
NOx	Annual	.999			100		
	1-Hour	114.00	177.00	291.00	3,200	55.31	90.90
CO	8-Hour	40.00			10,000		
	1-Hour	377.00			40,000		

NOTES:

Facility emissions based on the use of 0.3% fuel oil for the entire year.

All NAAQS, with the exception of the 3-hour SO_2 standard and the 1-hour NOx standard, are primary NAAQS. There is not primary NAAQS for 3-hour SO_2 concentrations -- 1,300 represents a secondary NAAQS. There are no primary or secondary NAAQS for 1-hour NOx concentrations -- 3,200 represents the MDEP 1-hour ambient NOx policy limit.

SOURCES: Exh. HO-RR-94, BE-48 pp. AP 29-1, 29-2.

TABLE 2

ELECTRIC AND MAGNETIC FIELDS

PRIMARY SITE

Output (MW)	Electric Field - KV/m (Kilovolts per meter) Southside	Electric Field - KV/m (Kilovolts per meter) Northside	Magnetic Field - mG (milligauss) Southside	Magnetic Field - mG (milligauss) Northside
0	0.30	0.15	15	20
150	0.30	0.15	3	7
300	0.30	0.15	8	6

ALTERNATIVE SITE

Ironstone Output (MW)	Electric Field (KV/m) Westside	Electric Field (KV/m) Eastside	Magnetic Field (mG) Westside	Magnetic Field (mG) Eastside
	EXISTING ROW 13 SOUTHWEST OF TAP			
0	.091	1.246	5.95	36.34
150	.091	1.246	6.94	42.40
300	.091	1.246	7.93	48.46
	EXISTING ROW 13 NORTHEAST OF TAP			
0	.091	1.246	5.95	36.34
150	.091	1.246	5.29	32.31
300	.091	1.246	4.63	28.27
	LOOP FROM EXISTING ROW 13 TO FACILITY			
0	.339	.339	16.1	16.1
150	.317	.362	23.5	14.0
300	.317	.362	30.9	12.1

TABLE 3

SIGNIFICANT SITE-DEPENDENT OPERATING COSTS
(1994 NET PRESENT VALUE)

	Edgar	Ironstone
Life Cycle Gas Cost	1,218,827,356	1,191,390,741
Incremental Generation Cost	0	36,182,793
Water Purchase	4,761,175	0
Water Treatment	3,114,760	4,036,836
Total Operating Costs	1,226,703,291	1,231,610,370
Operating Cost Advantage, Edgar Over Ironstone:		1,231,610,370
		- 1,226,703,291
		4,907,079

TABLE 4

SIGNIFICANT CAPITAL COSTS
(1994 $)

	Edgar	Ironstone
Site Procurement	0	8,756,457
Site Prep and Foundations	8,300,000	7,226,000
Heat Rejection System Components+	5,157,000	8,006,104
Electric Power Transmission	5,037,361	36,807,303 * 9,542,635 **
Fuel Handling	6,882,000	11,929,708
Municipal Improvements	2,400,000	0
Labor	37,411,600	32,858,600
Total Direct Cost	210,085,606	246,032,768 * 218,768,100 **

+ i.e., cost of steam cycle systems and equipment

* includes $27,264,668 cost for 17-mile segment of Millbury-Carpenter Hill transmission line

** excludes cost, 17-mile segment, Millbury-Carpenter Hill transmission line ($27,264,668)

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

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council, or within such further time as the Siting Council may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

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

FINAL DECISION
(ON REMAND)

Robert P. Rasmussen
Hearing Officer
October 27, 1993

On the Decision:
Phyllis Brawarsky
William Febiger

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APPENDICES:

LIST OF ABBREVIATIONS

Abbreviation	Explanation
AAL	Annual Allowable Ambient Limits
AGT	Algonquin Gas Transmission Company
Altresco	Altresco-Pittsfield, Inc.
Altresco Decision	Altresco-Pittsfield, Inc., 17 DOMSC 351 (1988)
Attorney General	Attorney General of the Commonwealth of Massachusetts
Attorney General Brief	Initial Brief filed by the Attorney General in EFSB 90-100R
Attorney General Reply Brief	Reply brief filed by the Attorney General in EFSB 90-100R
BACT	Best Available Control Technology
Basic Multiple Regression	An analysis prepared by the Attorney General based on up to three independent variables for each class
BPC	Bechtel Power Corporation
Btu	British Thermal Unit
Btu/kWh	British thermal unit per kilowatt hour
CAGR	Constant Annual Growth Rate
C&LM	Conservation and load management
Cedar Swamp	Acushnet Cedar Swamp State Reservation
CFB	Circulating Fluidized Bed
CGCC	Coal Gasification Combined-Cycle Unit

Abbreviation	Explanation
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992).
CLF	Conservation Law Foundation
CNB	City of New Bedford
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Company	Eastern Energy Corporation
Compliance Filing	EEC's environmental filing in EFSC 90-100A
Conference Report	Joint Explanatory Statement of the Committee of Conference, Federal Energy Guidelines, FERC Statutes & Regulations, Vol. I, at 5106
Court	Supreme Judicial Court sitting in the County of Suffolk
dBA	Decibels
Department	Department of Public Utilities
Destec	Destec Energy, Inc.
DOE	United States Department of Energy
DOE Forecast	Forecast based on DOE data
DSM	Demand Side Management
EEC	Eastern Energy Corporation
EEC Brief	Initial brief filed by EEC in EFSB 90-100R
EEC Compliance Decision	Eastern Energy Corporation, 25 DOMSC 296 (1992)

Abbreviation	Explanation
EEC Decision	Eastern Energy Corporation, 22 DOMSC 188 (1991)
EEC Reply Brief	Reply brief filed by EEC in EFSB 90-100R
Elaborate Multiple Regression	An analysis prepared by the Attorney General based on up to six independent variables for each class
Enron	Enron Power Enterprise Corporation
Enron Decision	Enron Power Enterprise Corporation, 23 DOMSC 1 (1991)
ENSR	ENSR Consulting and Engineering, Inc.
EPRI	Electric Power Research Institute
EUA	Eastern Utilities Associates
Expected Value Forecast	The expected value forecast prepared by NEPOOL and presented in its 1992 Resource Adequacy Assessment
FERC	Federal Energy Regulatory Commission
Fifth Report	Fifth Interim Report of the Special Commission Relative to the Regulation of the Location and Operation of Electric Utility Generation and Transmission Facilities and Other Related Matters, House No. 5349, January, 1974
First Report	First Report of the Massachusetts Electric Power Plant Siting Commission, House No. 5891, September, 1972
Fourth Report	Fourth Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6297, June, 1974
GDP	Gross Domestic Product

Abbreviation	Explanation
GDP Forecast	Forecast based on GDP
GEP	Good engineering practice
GNP Industrial Park	Greater New Bedford Industrial Park
gpd	Gallons per day
GOCC	A natural gas/oil-fired combined cycle unit with interruptible gas supply and a distillate oil back-up
GTF	NEPOOL Generation Task Force
GTF Forecast	Forecast based on 1991 GTF data
gwh	Gigawatt hours
HRSG	Heat recovery steam generator
H_2S	Hydrogen Sulfide
Hydro-Quebec	The Hydro-Quebec Phase II Project
IRM	Integrated Resource Management
kWh	Kilowatt Hour
lb/MMBtu	Pounds per million Btu
LGTI	Louisiana Gasification Technology, Inc.
Massachusetts End Year CAGR Forecast	CAGR projection of peak loads for the years 1992 to 2007 based on the NEPOOL-forecasted 2007 peak load in the Massachusetts reference forecast
Massachusetts linear Regression Forecast	Forecast based on the projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period

Abbreviation	Explanation
Massachusetts Reference Forecast	The NEPOOL 1992-2007 energy and peak load forecast for Massachusetts
Massachusetts CAGR Regression Forecast	Forecast based on the projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period
MASSPOWER	MASSPOWER, Inc.
MASSPOWER Decision	MASSPOWER, Inc., 20 DOMSC 301 (1990)
MCC	Methanol-Fired Combined Cycle Unit
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
Memorandum	Memorandum of the Hearing Officer, issued October 1, 1992 establishing procedures for the hearings on remand
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NEA	Northeast Energy Associates
NEA Decision	Northeast Energy Associates, 16 DOMSC 335 (1987)
Need Contingency Cases	Cases based on (1) adjusting the base supply forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing those nine adjusted supply forecasts with the demand forecasts
NEES	New England Electric System
NEPEX Forecast	The January through October, 1992 average fuel price for a specific NEPOOL unit with comparable fuel characteristics

Abbreviation	Explanation
NEPLAN	New England Power Planning Committee
NEPOOL	New England Power Pool
NEPOOL Agreement	The Agreement establishing the rights and obligations of NEPOOL members
NEPCo	New England Power Company
NESCAUM	Northeast States for Coordinated Air Use Management
NGCC	A natural gas-fired, combined cycle unit with firm, (i.e., 365 day), gas supply
NGW Forecast	Fuel price forecast based on projected 1992 through 1994 spot market gas prices quoted in "Natural Gas Week"
NO-COAL	Greater New Bedford NO-COALition
NO-COAL Brief	Initial brief filed by NO-COAL in EFSB 90-100R
NO-COAL Reply Brief	Reply brief filed by NO-COAL in EFSB 90-100R
NOx	Nitrogen Oxides
NU	Northeast Utilities
NUG	Non-Utility Generator
O&M	Operation and maintenance costs
PC	Pulverized Coal-fired power plant
PM-10	Particulate matter
PPAs	Power Purchase Agreements
PURPA	Public Utility Regulatory Policy Act of 1978

Abbreviation	Explanation
QF	Qualifying [cogeneration or small power producer] Facility
Reference forecast	1992 CELT Report Reference forecast
Reorganization Act	Chapter 141 of the Acts of 1992
Resource Assessment	1992 NEPOOL Resource Adequacy Assessment
RO	Residual oil-fired power plant
ROW	Right-of-Way
R.W. Beck	R.W. Beck and Associates
SCR	Selective catalytic reduction
Siting Board	Energy Facilities Siting Board
Siting Commission	Massachusetts Power Plant Siting Commission
Siting Council	Energy Facilities Siting Council
Siting Council IRM Decision	Rulemaking Regarding the Procedures by Which Additional Resources are Planned, Solicited, and Procured by Investor-Owned Electric Companies (Integrated Resource Management), Final Order On Rulemaking, 21 DOMSC 91 (1990).
SO_2	Sulfur Dioxide
Sixth Report	Sixth Interim Report of the Special Commission (under chapter 78 of the Resolves of 1971 and most recently revived and continued by chapter 10 of the Resolves of 1975) Relative to the Regulation of the Location and Operation of Electric Utility Generation and Transmission Facilities and Other Related Matters, House No. 4374, January, 1976
SNCR	Selective non-catalytic reduction

Abbreviation	Explanation
TEL	Threshold Effects Exposure Limits
Third Report	Third Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6190, March, 1973
TPY	Tons Per year
VOC	Volatile Organic Compounds
Wabash	Wabash River Coal Gasification Repowering Project
West Lynn	West Lynn Cogeneration
West Lynn Decision	West Lynn Cogeneration, 22 DOMSC 1 (1991)
Yankee	Yankee Energy Corporation
1989 TAG	Technical Assessment Guide issued by EPRI, dated September 1989
1991 CELT Report	NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1991-2006
1992 CELT Report	NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1992-2007
$/Mwh	Dollars per megawatt hour

SUMMARY OF DECISION

In City of New Bedford vs. Energy Facilities Siting Council (and a companion case), the Massachusetts Supreme Judicial Court remanded the Siting Council's decision in Eastern Energy Corporation, 22 DOMSC 188 (1991), for the Siting Council "to compare alternative energy resources in its review of Eastern's application." 413 Mass. 482, 484 (1992). The Court also identified four other issues that may arise on remand including one that stated: "because the statute mandates a necessary supply for the commonwealth, the Siting Council's specific finding that additional energy resources are needed for the New England area was inadequate." Id. at 489.

To address the remand issues, the Energy Facilities Siting Board first undertook a review of pertinent legislative history and directives. Specifically, the Siting Board reviewed: its enabling statute, G.L. c. 164, §§ 69G-69S; the NEPOOL Statute, G.L. c. 164A; the Public Utility Regulatory Policies Act of 1978; and the Reorganization Act that merged the Energy Facilities Siting Council with the Department of Public Utilities. [15-29]

With respect to comparing Eastern Energy Corporation's proposed 300-megawatt, coal-fired, circulating fluidized bed cogeneration project to alternatives, the Court stated that the Siting Council's past practice of requiring 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, comports with the council's statutory mandate. In past cases, the Siting Council compared the proposed project to generic alternative generating technologies. In this decision, the Siting Board found that requiring a review of generic alternatives is an acceptable method at this time to ensure that the statutory minimum impact standard is met. [44-65]

The Siting Board compared the proposed project to generic alternative generating technologies in terms of cost, environmental impact and reliability, and the ability to address the previously identified need. The generic alternative technologies compared were: a pulverized coal steam plant; a natural gas-fired, combined-cycle unit with firm (i.e., 365 days) gas supply; a natural gas/oil combined-cycle unit with interruptible gas supply and a low-sulfur, distillate oil back-up; a residual oil-fired steam unit; a coal-gasification combined-cycle unit; and a methanol-fired combined-cycle unit.[65-151] The Siting Board found that the Company has established that the proposed project is superior to all alternatives 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. [152-166]

With respect to the issue of a necessary energy supply for the Commonwealth, the Siting Board first undertook an analysis of what is meant by the term "necessary." In regard to the term "necessary," the Siting Board found it appropriate to adopt the Siting Council's past approaches to determining whether the addition of a proposed facility to the energy supply is necessary in this and future decisions. In the past, need has been found: (1) where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements; (2) in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs; or (3) principally for providing economic energy supplies relative to a system without the proposed facility. [178-182]

The Siting Board explained that given (1) the integration of the Massachusetts electric system with the regional electric system and the resulting link between Massachusetts and regional reliability, and (2) the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration, consideration of regional need is a central part of any need analysis for a power project not yet linked to individual utilities by PPAs. The Siting Board added that the 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 that this enactment acknowledged that power generating facilities would provide electric power across state lines. The Siting Board stated that few, if any, Massachusetts electric utilities produce all of their own electric power requirements. Electric utilities purchase power from other electric utilities as well as from nonutility generators in the New England region, and such purchases provide increased reliability to the Commonwealth's electric system. Therefore, the Siting Board found that an analysis of regional need must form the foundation for any analysis of Massachusetts need. [185-186]

The Siting Board also made the following findings with respect to this issue: (1) 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; (2) reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need; (3) the demonstration of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply; (4) 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; and (5) that the amount of a facility's 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 the facility. [186-189]

The Siting Board reviewed both the regional need analysis [192-234], and the Massachusetts need analysis [235-264]. Based on these reviews, the Siting Board found that in light of the uncertainty of the first year of need for the proposed project, 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. [267] The Siting Board found that the submission of (1) signed and approved PPAs which include capacity payments for at least 75 percent of the proposed project's output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output 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. [268]

Finally, the Siting Board noted that the approval of Eastern Energy Corporation's petition continues to remain conditional as EEC has yet to submit its filing relative to viability conditions. EEC will not receive a final approval of its proposed project until such time as the viability conditions have been satisfactorily met. At that time the Siting Board will determine whether the proposed project will provide a necessary energy supply for the Commonwealth with a minimum impact on environment at the lowest possible cost. [278-279]

I. INTRODUCTION

A. Procedural History

1. Eastern Energy Corporation's Initial Petition

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 ("GNB 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 188.[3,4]

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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 1st will 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 arises pursuant to G.L. c. 164, sec. 69H and G.L. c. 164, sec. 69I, which requires electric companies to obtain Siting Board approval for construction of proposed facilities. Eastern Energy Corporation, 22 DOMSC 188, 200-202 (1991) ("EEC Decision").

3 In the EEC Decision, the Siting Council conditionally approved EEC's petition. The conditions imposed on EEC fell into two categories; i.e., 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 further supplement the record. Id. at n.234.

4 A synopsis of the proceedings in EFSC 90-100, in addition to the major findings, (continued...)

Timely appeals of the EEC Decision were filed with the Supreme Judicial Court sitting in the County of Suffolk ("Court") 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 consolidated as Civil Action S-5856, City of New Bedford v. Energy Facilities Siting Council (and a companion case) ("City of New Bedford").[5]

2. EEC's Environmental Compliance Filing

On February 10, 1992, EEC filed its response to the environmental conditions contained in the EEC Decision ("Compliance Filing"). The Compliance Filing responded to the issues noted in the EEC Decision relative to noise, carbon dioxide ("CO_2"), and sulfur dioxide ("SO_2"). In the Compliance Filing, EEC also proposed additional changes to the proposed facility to further mitigate some of its environmental impacts. The Siting Council docketed this filing as EFSC 90-100A.

On July 20, 1992, the Hearing Officer issued the Tentative Decision in the proceeding. The Siting Council met on July 30, 1992, and by a majority vote adopted the Tentative Decision with some minor amendments. Eastern Energy Corporation, 25 DOMSC 296 (1992) ("EEC Compliance Decision").[6]

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[4](...continued)
conditions and orders of the Siting Council's final decision can be found in Appendix A of this decision.

[5] 413 Mass. 482 (1992). For a discussion of the appeal and the decision of the Court, see Section I.A.3, below.

[6] A synopsis of the proceedings in EFSC 90-100A, in addition to the major findings of the Siting Council's final decision, can be found in Appendix B of this decision.

3. The Appeal of the EEC Decision and The Court's Decision in City of New Bedford

As noted in Section I.A.1, above, appeals of the EEC Decision were filed by the Attorney General and CNB.[7] The Court noted that the Attorney General and CNB argued on appeal that the Siting Council:

-- failed to analyze the environmental impact of the proposed facility by failing to compare it with energy alternatives;

-- erred in finding a "need" for the proposed facility;

-- failed to make a finding that the new power from the proposed facility would be at the lowest cost to rate payers;

-- placed improper weight on the benefits of economic development to New Bedford and southeastern Massachusetts and failed to balance whether the environmental harm from the proposed facility was outweighed by other statutory objectives; and

-- failed explicitly and clearly to state its reasons for the final decision and failed to make adequate subsidiary findings to support its conclusions. 413 Mass. at 482.

Briefs were filed in the appeal in March and April, 1992.[8] Oral argument was held in May, 1992. On August 20, 1992, subsequent to the issuance of the EEC Compliance Decision, the Court issued its decision in 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 the following four "Other Issues which may Arise on Remand to the Council." Id. at 489-490.

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7 EEC's petition to intervene in the appeal was allowed by the Court.

8 Briefs were filed by the Attorney General, CNB, the Siting Council and EEC. An amicus curiae brief was filed by an assemblage of non-party environmental groups under the lead of the Conservation Law Foundation ("CLF"). The Attorney General also filed a reply brief in the matter.

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." Id. 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.

In conclusion, the Court remanded the matter to the Siting Council "for reconsideration of Eastern's application consistent with this opinion." Id.

4. The Proceedings on Remand

On September 2, 1992, the Company submitted a memorandum to the Siting Board regarding suggested procedures to be followed in response to the Court's decision in City of New Bedford. The Company argued that neither City of New Bedford nor case law nor the facts presented in the EEC case required additional evidentiary hearings. EEC suggested, however, that all parties be provided an opportunity to submit supplemental briefs and reply briefs on the limited issues raised by the Court's remand. The Hearing Officer solicited comments from all other parties in a memorandum issued the following day.

Comments were provided by the Attorney General, CNB, and Robert H. Ladino. The Attorney General argued that the Siting Board could choose not to reopen the record, but were it to do so, it could not approve the project. The Attorney General noted that the Court's opinion demonstrated that the record was incomplete and legally insufficient as a basis on which to site the project and argued that all of the major points of the EEC Decision needed to be reconsidered. He argued that the Siting Council had two options, it could reopen the record and hold additional evidentiary hearings or deny the petition.

CNB noted that the Siting Board had the discretion to deal with the issues raised by the Court's opinion based on the current record. Should the Siting Board decide to reopen the record, CNB argued that additional evidence should be presented only on those narrow issues raised by the Court's opinion.

Mr. Ladino argued that the Siting Board had two options available to it. The Siting Board could reopen the case and require the Company to submit a new application with supporting documentation that addressed the issues raised by the Court, or reopen the case and require the Company to submit new evidence with supporting documentation that addressed the issues raised by the Court. The first option, in effect, would require the Company to start the entire Siting Board process anew allowing for new intervenors and discovery. Under either option, Mr. Ladino argued that evidentiary hearings would be necessary, followed by briefs and the Siting Board's tentative and final decisions.

On October 1, 1992, the Hearing Officer issued a memorandum ("Memorandum") responding to the various arguments and establishing a procedural schedule for the proceedings on remand.[9] The proceedings on remand were docketed as EFSB 90-100R.

The Hearing Officer agreed with those parties who indicated that case law supported a finding that it was within the discretion of the Siting Board to decide whether additional evidentiary hearings were needed to address the issues raised by the Court. Memorandum at 5. The Hearing Officer noted that there was no direct order of the Court to do so. Id. Additionally, the Hearing Officer concurred with CNB that if additional hearings were necessary, those hearings would be restricted to only those narrow issues addressed by the

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[9] Two additional Petitions to Intervene had been filed with the Hearing Officer on September 23, 1992 by CLF and Cambridge Electric Light Company and Commonwealth Electric Company. As the Court did not raise any issues in City of New Bedford which were unknown at the time of EEC's original filing, the Hearing Officer denied both petitions as untimely, since both were filed over two years after the deadline for intervention. Hearing Officer's Procedural Order of October 27, 1992.

Court. Id. The Hearing Officer rejected the argument of the Attorney General that all of the major points of the EEC Decision were in need of reconsideration. Id. The Hearing Officer noted, as set forth in Section I.A.3, above, that the Court remanded this case to the Siting Council on the basis of one specific issue -- a comparison of alternative energy resources -- and raised four additional areas of concern which might arise on remand. Id.

In response to arguments that the Hearing Officer should reopen the record on the issue of alternative energy resources, the Hearing Officer explained how the record on this issue had already been developed. Id. at 5-6. EEC's original petition was filed in January 1990. At that time, the Siting Council had reviewed petitions to construct power generating facilities of non-utility generators in two other cases[10] and was in the process of reviewing a third.[11] In all three of those cases the Siting Council reviewed the proposed facilities in a manner which incorporated a comparison of alternative energy options, a standard which was specifically approved by the Court in City of New Bedford.[12,13]

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10 See, Altresco-Pittsfield, Inc., 17 DOMSC 351 (1988) ("Altresco Decision"); Northeast Energy Associates, 16 DOMSC 335 (1987) ("NEA Decision").

11 See, MASSPOWER, Inc., 20 DOMSC 301 (1990) ("MASSPOWER Decision").

12 The Court stated "prior to this application the 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 council's statutory mandate" (emphasis added). 413 Mass. at 485.

13 In the MASSPOWER Decision, the Siting Council expressed its concerns with this standard and stated its intention to develop a new standard by which non-utility power generation facilities would be reviewed. 20 DOMSC at 349-352. A new standard was first utilized by the Siting Council in West Lynn Cogeneration, 22 DOMSC 1 (1991) ("West Lynn Decision"). The new standard utilized a comprehensive evaluation to: (1) ensure that the proposed project would provide reliability, economic and/or environmental benefits to the Commonwealth in sufficient magnitude to offset any impacts on the Commonwealth's resources and would provide a least-cost energy supply; (2) better coordinate the evaluation of alternative resource options through the Integrated Resource Management ("IRM") process; and (3) place greater emphasis on determining whether a proposed project was consistent with the resource use and (continued...)

The Hearing Officer noted that EEC's initial petition included an analysis of alternative energy options consistent with the earlier non-utility generation cases. Id. at 5, 6. Additionally, a review of the record in the EEC proceeding (EFSC 90-100) showed that several parties issued discovery and examined witnesses on the issue of energy alternatives and briefing on the issue of alternative energy options was done by both parties and interested persons. The Hearing Officer, therefore, concluded that the record was sufficiently developed on the issue of energy alternatives to address the concerns of the Court in City of New Bedford and, therefore, found no reason to exercise the Siting Board's discretion to reopen the record to further develop this part of the record. See, Celia M. Sniffin v. The Prudential Insurance Company of America, 419 N.E.2d 308, 11 Mass. App. Ct. 714 (1981).[14] Memorandum at 6.

In response to arguments relative to the remaining issues raised by the Court, i.e., the issues of the need for, and the cost of, power from the proposed project, the Hearing Officer noted that the record also contained information on both of these issues.[15] Id. at 7. The Hearing Officer further noted that the Court's concerns on these issues indicated that the Siting Council's findings were either inadequate, inappropriate, or not in conformance with the legislative mandate. Id. The Court did not, however, indicate that the Siting Council

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[13](...continued)
development policies of the Commonwealth. West Lynn Decision, 22 DOMSC at 59-60. See also, EEC Decision, 22 DOMSC at 279-281. The EEC Decision was only the second case in which the new standard was used by the Siting Council. This new standard will be more fully discussed in Sections II.B.1 & 2, below.

[14] Similar discretion is afforded agencies under the Federal Administrative Procedure Act. Southwest Sunsites, Inc. v. FTC, 785 F.2d 1431 (9th Cir. 1986), cert. denied, 479 U.S. 828, 107 S.Ct. 109, 93 L.Ed.2d 58 (due process not violated by lack of notice and new hearings where party understood issue and was afforded full opportunity to present case).

[15] The final issue identified by the Court, the need to further state the reasons for the Siting Council's determination of each issue, related to the decision drafting process and not to any deficiency in what was contained in the record. The Hearing Officer, therefore, found no basis to reopen the record based on that issue. Memorandum at n.7.

could not correct these findings based on the developed record. Id. The Hearing Officer found that the record was sufficiently developed on these issues to address the concerns of the Court, and, with one exception, found no reason to exercise the Siting Board's discretion to reopen the record to further develop these issues. Id.

Nevertheless, the Hearing Officer acknowledged that considerable time had passed since the EEC Decision was issued during which information relevant to issues which were to be addressed on remand may have become dated. Id. at 8. Therefore, consistent with procedures used in the original proceeding "to ensure that the record in this case reflects the most recent information," the Hearing Officer reopened the record for the purpose of updating information which was already contained in the record. Id. The Hearing Officer noted that the rationale for allowing updated information was not to relitigate a fully developed record, but rather, to provide the most current data on information which was already in the record. Id.

On the issue of energy alternatives, the Hearing Officer restricted new information to updated information on the costs and environmental impacts of the proposed project and alternative energy resources, including alternative technologies, that have changed due to the passage of time. Id. Information as to new energy alternatives which were not addressed in the initial or compliance proceedings was to be permitted only to the extent that there was a showing that such alternatives did not exist at the time of the development of the original record. Id.

On the issue of need, the Hearing Officer followed the procedure established relative to the reopening of the record in EFSC 90-100 to incorporate the New England Power Pool ("NEPOOL") Forecast Report of Capacity, Energy, Loads and Transmission, 1991-2006 ("1991 CELT Report") (See Appendix A, below). In the present proceeding, the Hearing Officer introduced three 1992 NEPOOL documents into the record, including the NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission, 1992-2007 ("1992 CELT Report"), and noted that NEPOOL documents were relevant to the issue of the Commonwealth's need for energy. Id. at n.9. All parties were provided an opportunity to submit additional information or analyses concerning the projections contained in the 1992 CELT Report.[16] Id. at 9.

Finally, all parties were allowed to request updated exhibits from the appropriate responsive party on the limited issues of need (including Massachusetts need), cost and environmental impacts of energy alternatives, and power costs. Id. The Hearing Officer's schedule expected final reply briefs to be filed on November 25, 1992, thereby concluding the development of the record on remand. Id. at 10.

On October 13, 1992, the Attorney General and the Greater New Bedford NO-COALition ("NO-COAL") filed a motion to revise the Siting Board's procedural schedule on remand and to temporarily stay the proceedings arguing, in part, that the proposed schedule denied the intervenors the right to rebut EEC's case guaranteed under M.G.L. c.30A, § 11(3). Prior to a decision by the Hearing Officer, EEC entered into negotiations with the Attorney General and NO-COAL to develop an approach to the remand proceedings that would be acceptable to all parties. A negotiated settlement was filed with the Hearing Officer on October 22, 1992.

Pursuant to the negotiated settlement, EEC agreed to submit an affirmative case on the issues of need and alternative energy resources followed by a period of discovery. The intervenors then would submit their affirmative case followed by an additional round of discovery. Hearings were to commence the week of December 15, 1992, and continue into January 1993, if needed. One issue which was left unresolved was the schedule for the submission of final briefs.

By memorandum issued October 27, 1992, the Hearing Officer accepted the negotiated settlement as a resolution of all issues raised by the Attorney General's and NO-COAL's motion of October 13, 1992 with the exception of the briefing schedule. The briefing schedule issue was left unresolved until such time as the additional hearings had been concluded.

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16 At the time of his memorandum, the Hearing Officer foresaw no need for additional hearings. However, he noted that the issue of whether to reconvene hearings might be revisited after receipt of all updated information.

The Siting Board conducted 18 days of evidentiary hearings commencing on December 16, 1992 and ending February 16, 1993. EEC presented two witnesses who had testified in the earlier proceedings: James H. Slack, a senior program manager for ENSR Consulting and Engineering ("ENSR"), who testified regarding the comparison of alternative technologies; and Glen Harkness, vice president of ENSR, who also testified regarding the comparison of alternative technologies. EEC presented one additional witness: Richard La Capra, a utility analyst and principal of La Capra Associates, who testified regarding financial aspects of alternative technologies and the need for the proposed facility.

The Attorney General presented four witnesses: Paul Horowitz, an independent public policy consultant specializing in energy resource planning and related issues, who testified regarding demand side management ("DSM") issues; Kenneth M. Keating, an evaluation consultant for the Bonneville Power Administration, who testified regarding DSM evaluations; David L. Breton, a manager of process systems engineering for Destec Energy, Inc. ("Destec"), who testified regarding coal gasification; and Don M. Shakow, a self-employed economist, who testified regarding the need for the proposed facility.

NO-COAL presented six witnesses: Mr. Ladino, a self-employed energy engineer, who testified regarding power plant operations and environmental outputs; Peter J. Booras, president of Yankee Energy Corporation ("Yankee"), who testified regarding Yankee and methanol backup supply; Charles R. Fink, a consulting engineer for Yankee, who testified regarding methanol supply, delivery, and its use as a power plant fuel; Richard C.M. Calvert, manager of business development for Newport News Industrial Corporation, who testified regarding the methanol plantship; Sara Wright, an assistant project manager for Yankee, who testified regarding legislative matters relative to methanol production and use; and George Nassopoulos, a naval architect and mechanical engineer, who testified regarding the methanol plantship.

The Hearing Officer entered 312 exhibits into the record, consisting largely of responses to information and record requests. EEC entered 327 exhibits into the record.

The Attorney General entered 158 exhibits into the record. NO-COAL entered 28 exhibits into the record, five of which were sponsored by Mr. Ladino.[17]

Initial briefs were filed by EEC ("EEC Brief"), the Attorney General ("Attorney General Brief"), and NO-COAL ("NO-COAL Brief") on March 15, 1993. Reply briefs were filed by EEC ("EEC Reply Brief"), the Attorney General ("Attorney General Reply Brief"), and NO-COAL ("NO-COAL Reply Brief") on March 23, 1993.

5. The EEC Decision on Remand

As noted in Section I.A.3, above, the Court remanded the EEC Decision to the Siting Council for reconsideration of EEC's application consistent with the Court's opinion. City of New Bedford at 490. In so doing, the Court faulted the Siting Council for failing to include in the EEC Decision "a statement ... including determinations of each issue of fact or law necessary to the decision." Id. Thus, the Court directed the Siting Council to "explicitly state the basis of its determination, with adequate subsidiary findings to support its conclusion." Id. at 491. The Court's concern was that the failure of an agency to give a "guide to its reasons" frustrates the Court's ability to review the agency's decision. Id. at 490.

In the course of this EEC Decision on remand, the Siting Board will address each element of the Court's opinion and each issue necessary to the decision in light of these directives. As an initial matter, however, the Siting Board must first address a dilemma which we face as a result of two legislative enactments[18] and the Court's decision in City of

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

18 The Legislature enacted Chapter 150, § 326A of the Acts of 1990 on August 1, 1990 and approved Chapter 141, § 46 of the Acts of 1992 on July 21, 1992. Both enactments state that nothing contained therein shall be interpreted as changing the Siting Board's body of precedent.

The Siting Board notes that the last of these two enactments became law in July, 1992, post-dating the EEC Decision, Enron Power Enterprise Corporation, 23 DOMSC 1 (continued...)

New Bedford. Specifically, in City of New Bedford the Court noted that the Siting Council's review as it relates to a comparison of alternatives did not comport with the statutory mandate. Further, the Court's decision appears to call into question the Siting Council standard of review regarding need. In light of legislative enactments expressly approving Siting Council precedent, the Siting Board must determine what standards of review are appropriate for use in this and future cases.

The Siting Board is very much aware that the duty of statutory interpretation is for the courts. Cleary v. Cardullo's, Inc., 347 Mass. 337, 344 (1964). This, however, does not mean that administrative agencies have no role to play in the interpretation of their enabling statute. As the Court held in Massachusetts Organization of State Eng'rs. & Scientists v. Labor Relations Commission:

> Ordinarily precepts of statutory construction instruct us to accord deference to an administrative interpretation of a statute. School Comm. of Wellesley v. Labor Relations Comm'n., 376 Mass. 112, 116 (1978). Application of these principles is especially significant "where, as here, an agency must interpret a legislative policy which is only broadly set out in the governing statute." School Comm. of Springfield v. Board of Educ., 362 Mass. 417, 442 (1972).

389 Mass 920, 924 (1983).

The Siting Board is also aware that a statutorily created board has only the powers, duties and obligations expressly conferred upon it by the statute that created it or such as are reasonably necessary for the proper functioning of the board in carrying out and accomplishing the purpose for which it was established. Hathaway Bakeries v. Labor Relations Comm., 316 Mass. 136, 141 (1944).

As will be discussed fully in the following sections, the legislative policy contained in the Siting Board's enabling legislation as it applies to non-utility developers such as the present petitioner is a broad statement of policy. No specific direction has been given by the

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[18](...continued)
(1991) ("Enron Decision") -- a decision which also used the same standard of review as was used in the EEC Decision -- as well as oral argument in the appeal of the EEC Decision.

Legislature as to how to review a jurisdictional facility outside the realm of a utility's long-range forecast.[19]

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). The Court has also held that, in construing a statute, common words and phrases employed in the statute are to be accorded their usual meaning, and each must be given its appropriate effect without emphasizing one at the expense of the others, so that together they constitute an effective piece of legislation in harmony with common sense and sound judgment. 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.

Thus, the Siting Board must reconcile the directives of the Court in City of New Bedford with its statutory directives in a manner that acknowledges: (1) the Court's authority with regard to statutory interpretation; (2) the history of the development of, and the amendment to, the Siting Board's enabling statute; and (3) the Legislative support for the Siting Board's precedent.[20] Further, the Siting Board must ensure that all words and

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19 The Legislature, however, has acknowledged that applications to construct facilities that generate electricity will be filed by non-utility developers outside of any long-range forecast review process. See, G.L. c. 164, § 69J1/2.

20 In Earl W. Johnson's (dependents) Case, two court decisions preceded a legislative enactment that amended the statute thereby changing the law as interpreted in those two cases. 318 Mass. 741,745 (1945). The Court acknowledged the presumption that the Legislature was familiar with those cases at the time of the enactment and intended to change a presumption of that statute which the Court had interpreted otherwise. Id.

In the present case, the Legislature has specifically endorsed the precedent of the Siting Board thereby making it reasonable to presume that the Legislature was familiar with (continued...)

phrases of its statute must be interpreted in a manner that makes the enabling legislation, as well as the other legislation that affects the Siting Board's operation, "effective piece[s] of legislation in harmony with common sense and sound judgment." The Siting Board can neither ignore the Court's opinion in City of New Bedford or the above cited cases, nor ignore the Legislature's enactments. In order to accomplish this, the Siting Board, consistent with Wilcox, supra, must interpret its enabling statute in connection with its development, prior legislation, their progression through the Legislature and the history of the times.[21] The Siting Board, therefore, commences this decision on remand with a description of the legislative history of its enabling statute. The Siting Board reviews the development of the Siting Council's standards of review in response to these directives in Sections II.B.1 and II.C.1, below. This history provides the context for the Siting Board's review of the specific elements of the Court's directives relating to alternatives and need in Sections II.B.2 and II.C.2, below, and the Siting Board's resulting evaluation of the record in this case in Sections II.B.3 - 7 and II.C.3 - 5, below. Finally, the Siting Board considers the other issues raised by the Court in City of New Bedford in Section III, below.

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[20](...continued)
the Siting Council's decisions when it acted. In addition, there has been no legislative action to change the Siting Board's statute in regard to its facility reviews in response to those Siting Board decisions.

The Siting Board is also mindful of the rule of statutory construction that "legislative action by amendment or appropriations with respect to other parts of a law which have received a contemporaneous and practical construction may indicate approval of interpretations pertaining to the unchanged and unaffected parts of the law." Sutherland Stat. Const. § 49.10, at 76-77 (5th ed.)

[21] The Siting Board notes the Court's instruction that to construe a legislative enactment consistently with legislative intent, its words must be considered in connection with the cause of the enactment, the problems sought to be remedied, and the main objectives to be accomplished. Registrar of Motor Vehicles v. Board of Appeal on Motor Vehicle Liability Policies & Bonds, 382 Mass. 580, 585 (1981).

B. Legislative History and Directives

1. The Siting Board's Enabling Statute: G.L. c. 164, §§ 69G-69S

In 1971, the Legislature created the Massachusetts Electric Power Plant Siting Commission ("Siting Commission") "for the purpose of making an investigation and study of the regulatory procedures employed by the Commonwealth and by its political subdivisions relative to the location and operation of electric utility generating and transmission facilities." St. 1971, c.78. During its tenure, the Siting Commission issued six reports.[22] The Third Report details the background against which the Siting Commission was established and includes an analysis of a recommended siting bill which was appended to that report. That bill, with minor revisions, was enacted as St. 1973, c.1232, inserting §§ 69G-69R of c. 164 of the General Laws.

As is clear from the Siting Commission's Third Report, the cause of the enactment of §§ 69G-69R was the onset of the so-called "energy crisis" in the early 1970's. Third Report at 10, 11, 15. The Siting Commission recognized that while some elements of the public supported development and construction of electric power facilities, other elements opposed such development and construction. Concerned that a collision of these "contradictory public attitudes about electric power" could slow the orderly development of essential power supplies, the Siting Commission proposed the siting bill to accommodate these competing

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22 First Report of the Massachusetts Electric Power Plant Siting Commission, House No. 5891, September, 1972 ("First Report"); Second Report of the Massachusetts Electric Power Plant Siting Commission, House No. 5892, December 27, 1972 ("Second Report"); Third Report of the Massachusetts Electric Power Plant Siting Commission, House No. 6190, March 30, 1973, ("Third Report"); Fourth Report of the Massachusetts Siting Commission, House No. 6297, June 13, 1974 ("Fourth Report"); Fifth Interim Report of the Special Commission Relative to the Regulation of the Location and Operation of Electric Utility Generation and Transmission Facilities and Other Related Matters, House No. 5349, January 6, 1975 ("Fifth Report"); Sixth Interim Report of the Special Commission (under Chapter 78 of the Resolves of 1971 and most recently revived and continued by Chapter 10 of the Resolves of 1975) Relative to the Regulation of the Location and Operation of Electric Utility Generation and Transmission Facilities and Other Related Matters, House No. 4374, January 8, 1976 ("Sixth Report").

interests and prevent the feared collision. Id. at 8, 9. In particular, the Siting Commission sought to mitigate the effect of certain factors which were perceived as delaying new and needed capacity, such as insufficient advance public notice and environmental challenges. Id. at 8, 9, 15. In addition, the Siting Commission sought to address concerns that devices required for environmental protection and enhancement would reverse the long-term trend of decreasing average costs which the electric utility industry and its consumers had enjoyed. Id. at 9.

The main objectives to be accomplished in enacting §§ 69G-69J of c. 164 were "to help eliminate the delays due to environmental opposition by requiring an early public disclosure of the companies' plans ... in regards to the expansion and construction of facilities" and to "enable the Siting Council to give adequate consideration to [the] environment." Id. at 15, 20.[23]

Thus, in 1973, the Siting Council was established "which shall be responsible for implementing the energy policies contained in sections sixty-nine H to sixty-nine R,[24] inclusive, 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.[25] Among the

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[23] The main objective in enacting §§ 69K-69O of the Siting Council's statute was to establish a procedure by which appeals from local regulatory decisions concerning the siting of new facilities could be resolved. Third Report at 22. Under these provisions, the Siting Council may, under certain circumstances, issue a Certificate of Environmental Impact and Need for a proposed facility. If granted, the certificate takes precedence over any approval, consent, permit or condition required by a state agency or local government for the construction, operation or maintenance of the facility. Id.; G.L. c. 164, § 69K.

[24] Section 69S, relative to eminent domain with respect to oil pipelines, Section 69H1/2, relative to hydropower generation facilities, and Section 69J1/2, relative to fees for applications to construct electricity facilities, were added by legislative action in 1976, 1979, and 1990, respectively.

[25] The Reorganization Act made several organizational changes to G.L. c. 164 as it moved the Siting Board's responsibilities for the review of long-range forecasts to the Department. Prior to the Reorganization Act, the requirements relative to long-range (continued...)

Siting Council's duties was the review of long-range forecasts of electric companies.[26,27] G.L. c. 164, § 69I (1973). Electric companies were prohibited from commencing

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[25](...continued)
forecasts and facility reviews were contained in G.L. c. 164, §§ 69I and 69J. As a result of the Reorganization Act's changes, the current version of G.L. c. 164, § 69I contains the requirements relative to long-range forecasts, and the current version of § 69J contains the requirements relative to the review of petitions to construct energy facilities.

The discussion in the text above relates to the Siting Council's legislation prior to the Reorganization Act.

[26] Every electric company was required to file a "long-range forecast with respect to the electric power needs and requirements of its market area." G.L. c. 164, § 69I (1973). The Siting Commission stated that it "believe[d] that the definition stated [in Section 69G] will cover every electric <u>utility</u> company doing business in Massachusetts" (emphasis added). <u>Third Report</u> at 17.

This section was later amended, pursuant to recommendations of the Siting Commission in the <u>Fourth Report</u>, to include a similar filing requirement for gas companies. Acts of 1976, c. 468, § 2.

[27] Each long-range forecast was required to include, among other things:

> (3) A description of actions planned to be taken by the company which will affect its capacity to meet such needs, including, but not limited to: expansion, reduction, or removal of existing facilities; construction or acquisition of additional facilities; a description of alternatives to planned action such as other methods of generating, other site locations, other sources of electrical power, and no additional electrical power; [and] a description of the environmental impact of each proposed facility.

G.L. c. 164, § 69I (1973).

In 1986, the description of actions planned was expanded to include "a reduction of requirements through load management." Acts of 1986, c. 466, § 1. In addition, the list of "alternatives to planned action was expanded to include "facilities which operate on solar or geothermal energy and wind or facilities which operate on the principle of cogeneration or hydrogeneration." <u>Id.</u>

"construction of a facility at a site unless the facility [was] consistent with the most recently approved long-range forecast." Id. The requirement to file a long-range forecast before construction of a facility could be commenced was to "help to eliminate delays due to environmental opposition by requiring an early public disclosure of the companies' plans." Third Report at 15. The Siting Commission noted their belief that this requirement would provide advance public disclosure and adequate forecasting, research and development in response to the depiction of the Federal Power Commission that failure to do this had delayed needed power capacity. Id. at 19.

The Siting Council was required to hold an adjudicatory hearing on every long-range forecast and was required to approve a long-range forecast if the Siting Council determined that it met the requirements listed in G.L. c. 164, § 69J.[28] Thus, the Siting Council's enabling statute required the review of the long-range forecast of an electric (and later, gas) company with respect to the electric power (and later, gas) needs of its market area[29] and

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[28] Section 69J included the following requirements:

> all information relating to current activities, facilities agreements and electric energy policies as adopted by the commonwealth is substantially accurate and complete; projections of demand for electric power and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods; projections relating to service area, facility use and pooling arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved and reasonable projections of other companies in the New England area; and plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth.

G.L. c. 164, § 69J (1973).

[29] An electric utility's market area, or service territory as it is called by the Department, provides the utility with a monopoly on the retail sales therein, but carries with it an (continued...)

prohibited the construction of a facility that was not consistent with the most recently approved long-range forecast. The Siting Commission envisioned the planning process of such companies to be an avenue to both identify the need for new facilities and notify the public of the plans to construct such facilities.

Throughout the development of G.L. c. 164, no independent procedure for the review of a petition to construct a power generating facility outside the confines of a long-range forecast or supplement thereto was ever established.[30] During the tenure of the Siting

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[29](...continued)
obligation to serve all retail customers within the jurisdiction defined by that service territory. Non-utility developers have no defined service territory, no obligation to serve and no right to sell at retail.

[30] The Siting Commission, however, recommended Siting Council jurisdiction over the siting of oil facilities in its Fifth Report and legislation to effect this was passed as Chapter 617 of the Acts of 1975. As oil facilities are not constructed by electric or gas companies subject to the requirement of G.L. c. 164 to submit long-range forecasts of needs and requirements, the Legislature required companies planning to construct an oil facility to file a notice of intention to construct the facility with the Siting Council "[n]ot later than one year prior to commencement of construction." Acts of 1975, c. 617, § 7; G.L. c. 164, § 69I. Companies could not commence construction thereof until the Siting Council had approved the notice of intention to construct "as provided for in section sixty-nine J." Id. The Siting Commission noted that applicants who plan "to build an oil facility within the Commonwealth would now have to follow procedures analogous to those established for electric and gas companies." Fifth Report at 22.

As a result, G.L. c. 164, § 69J was amended by adding the following additional language after "commonwealth" (see n.28, above):

> and are consistent with the policies stated in section sixty-nine H to provide a necessary power supply for the commonwealth with a minimum impact on the environment at the lowest possible cost; and in the case of a notice of intention to construct an oil facility, that all information regarding sources of supply for such facility and financial information regarding the applicant and its proposed facility are substantially accurate and complete, that it is satisfied as to the adequacy of the applicant's capital

(continued...)

Commission, this approach was sufficient to maintain oversight of electric power generating facilities as only electric utility companies would endeavor to construct such facilities.

The planning process of electric utilities, however, was affected by two additional significant legislative enactments -- the NEPOOL Statute (G.L. c. 164A), and the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA"). The former, enacted the same year as the Siting Council's enabling legislation, acknowledged the regional nature of utility power planning, while the latter opened the power generation market to two new classifications of non-utility developers -- cogenerators and small power producers.[31] 16 U.S.C.A. § 824a-3. EEC falls into the first of these two classifications.

As the Siting Council's review of long-range forecasts was impacted by both of these enactments, it is necessary to review their directives.

2. The NEPOOL Statute: G.L. c. 164A

Through the enactment of Chapter 571, Section 2, of the Acts of 1973, (codified as G.L. c. 164A, §§ 1 - 27), the Legislature acknowledged the need for regional planning and cooperation in the provision of electric energy to electric consumers in the Commonwealth and New England. Chapter 164A authorized electric utilities in Massachusetts to participate

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[30](...continued)

> investment plans to complete its facility, the long term economic viability of the facility, the overall financial soundness of the applicant, the qualification and capability of the applicant in the transshipment, transportation, storage, refining and marketing of oil or refined oil products, and that plans including buffer zones or alternatives thereto for the applicant's new facility are consistent with current health, environmental protection and resource use and development policies as adopted by the commonwealth.

Acts of 1975, c. 617, § 8.

[31] A cogeneration facility produces both electric and thermal energy for use. Cogeneration facilities, such as the EEC project, are built primarily to produce electricity but utilize the heat produced in the production of electric energy for other industrial processes. As these industrial processes would otherwise require the use of additional fuel, through the use of cogeneration, fuel has been used more efficiently.

with all electric utilities operating in New England in a contractual agreement to be known as the NEPOOL agreement.[32] G.L. c. 164A, § 1. The NEPOOL agreement "provides for cooperation and joint participation in developing and implementing a regional bulk power supply of electricity." Id. The NEPOOL agreement was created, among other things, to provide for the pooling of power and the coordination of planning of NEPOOL members. Id., § 2. In addition, Chapter 164A allows domestic electric utilities[33] that are NEPOOL members "jointly or separately to plan, ... construct, ... use, own, ... or otherwise participate in electric power facilities or portions thereof within or without the commonwealth." Id., § 3. Similarly, foreign electric companies that are NEPOOL members "have in addition the power jointly with one or more other electric utilities, including at least one domestic electric utility, to construct, ... use, own, ... or otherwise participate in electric power facilities or portions thereof within this commonwealth or the product or service therefrom." Id., § 4.

It is clear from the enactment of Chapter 164A that the Legislature was aware of the need for planning to meet electric power needs which extend beyond the borders of the Commonwealth.[34] Additionally, it is clear that the Legislature was aware that electric

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32 Power pool agreements such as the NEPOOL agreement were authorized under the Federal Power Act. 16 U.S.C.A. § 791a et seq. The NEPOOL agreement was moved into evidence in these proceedings. See, Exh. HO-MN-20.

33 A "domestic electric utility" is an electric utility organized under the laws of, or having its principal place of business in, the Commonwealth. G.L. c. 164A, §1. A "foreign electric utility" is any electric utility other than a domestic electric utility. Id.

34 In the Third Report, the Siting Commission reviewed the role that NEPOOL played in electric resource planning for the New England states. Third Report at 12-13. The Siting Commission expected that this role would not be lost in the siting process in Massachusetts. Id. at 13. The Siting Commission noted:

> [b]ecause of the importance of regional planning in ensuring the reliability of our entire electric system in New England as well as the minimizing of cost factors to the electric industry, again with the ultimate benefit descending to the consumer, this

(continued...)

power generating facilities built in the Commonwealth could provide electric power for consumers in states other than Massachusetts. Similarly, electric power generating facilities located in other states could benefit electric consumers in the Commonwealth.

Through the enactment of G.L. c. 164, §§ 69G-69R and c. 164A, the planning and cooperation of electric utilities in meeting the electric needs and requirements of consumers in the Commonwealth, as well as in the New England region, had been authorized by the Legislature. Domestic electric utilities were still required to file long-range forecasts for their market areas; however, electric needs and requirements could be met through the pooling of power and joint ownership of electric generating facilities among domestic and foreign electric utilities.[35] Planning on a regional basis to ensure reliability to the electric system and to minimize costs to consumers was envisioned to ensure that the Commonwealth would be provided with necessary energy at the lowest possible cost. Thus, by 1978, Massachusetts and the other New England states had an established cooperative regional electric power system that was amenable to the changes to the electric power market which resulted from the enactment of PURPA.

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[34](...continued)

> Special Commission deemed it important to include the various provisions of the siting bill which allow for regional cooperation.

Id. See, e.g., G.L. c. 164, § 69I ("a long-range forecast with respect to the electric power needs and requirements of its market area, taking into account wholesale bulk power sales or purchases or other cooperative arrangements with other electric companies"); and G.L. c. 164, §§ 69I and 69J ("projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved and reasonable projections of activities of other companies in the New England area").

[35] The Siting Board notes that Massachusetts is serviced by three electric utilities that are subsidiaries of larger multi-jurisdictional electric companies -- New England Electric System ("NEES"), Eastern Utilities Associates ("EUA"), and Northeast Utilities ("NU"). NEES, EUA and NU are subject to oversight by the Federal Energy Regulatory Commission ("FERC"), but provide electric power to Massachusetts and several neighboring states through various subsidiary electric utility companies.

3. PURPA

PURPA was enacted on November 9, 1978 as Public Law 95-617. In enacting this legislation, the United States Congress stated its purposes were: "to encourage -- (1) conservation of energy supplied by electric utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates for electric consumers." 16 U.S.C.A. § 2611.

Pursuant to Section 210 of PURPA, the FERC was directed to prescribe rules to encourage cogeneration and small power production.[36] 16 U.S.C.A. § 824a-3(a). This section also required states to implement such rules for each electric utility for which it has ratemaking authority.[37] 16 U.S.C.A. § 824a-3(f). Further, this section required electric utilities to purchase electric energy from a qualifying [cogeneration or small power producer] facility ("QF")[38] at rates that are just and reasonable to the electric consumers of the electric utility, non-discriminatory against other QFs, and not to exceed the incremental cost to the electric utility of alternative electric energy.[39] 16 U.S.C.A. § 824a-3(b). Costs to consumers of electric energy, thereby, would be maintained at, or below, current levels. Joint Explanatory Statement of the Committee on Conference, Federal Energy Guidelines, FERC Statutes & Regulations, Vol. I, at 5106 ("Conference Report"). FERC was

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36 The FERC regulations enacted in response to this directive are codified at 18 C.F.R. Part 292.

37 In response to this directive, the Department promulgated regulations applicable to those electric utilities that sell electricity at retail in Massachusetts and that are subject to the jurisdiction of the Department. See 220 C.M.R. Part 8.00. The Department's IRM regulations supersede these regulations and provide a more comprehensive electric power procurement process for Massachusetts electric utilities. See 220 C.M.R. Part 10.00. See also notes 43, 44, & 45 and associated text, below.

38 As was noted in the EEC Decision, EEC is a QF under PURPA. 22 DOMSC at 195.

39 The term "incremental cost of alternative electric energy" is defined as the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source. 16 U.S.C.A. § 824a-3(d).

prohibited from authorizing QF's to sell at retail, i.e., any sale for purposes other than resale; however, states were allowed to permit such retail sales.[40]
16 U.S.C.A. § 824a-3(a).

The Committee on Conference warned against the use of utility type regulation over firms interested in cogeneration as it could result in a disincentive to their entering the market. Conference Report at 5106. In fact, PURPA specifically exempts QF's "from state laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities." 16 U.S.C.A. § 824a-3(e)(1).

The Committee on Conference also recognized that QFs were not identical to electric utilities as they are not guaranteed a rate of return on their activities generally or on their activities vis-a-vis the sale of power to a utility.[41] Conference Report at 5105. The risk in the development of a cogeneration or small power producing QF, unlike a utility power producing facility, is carried by the developer, and not, ultimately, the ratepayer, as there is no guaranty that development costs will be recoverable. Id. at 5106.

By enacting PURPA, Congress acted in a manner to promote conservation of electric energy and the increased efficiency in the use of resources by electric utilities. To accomplish these goals, PURPA mandated that the power generating market be opened to a new class of producers of electric energy, i.e., non-utility developers. The risks of increased electric rates resulting from potential cost overruns related to the construction of power producing facilities, as a result, was, in part, shifted from electric consumers, i.e., utility ratepayers, to the non-utility developers. Ratepayers of electric utilities would further benefit as the cost of electric energy that an electric utility was required to purchase from a cogenerator would be no higher than the incremental cost of alternate electric energy to that electric utility, and was likely to be lower.

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40 Massachusetts has no provision for retail sales of electricity by QFs.

41 QFs also differ from electric utilities in that they have no state-regulated, monopolistic service territory, and they have no obligation to serve. See n. 29, above.

PURPA left siting and most rate-making issues related to this new class of developers to the purview of individual state regulators. PURPA, however, did not alter the reality of a regional market for electric power;[42] rather, it expanded the supply options available to this market through the development of this new QF class of electric energy providers. By increasing competition through the development of new types of generating capacity, electric utilities would have a greater selection of options available to them, and states could effect the goals of PURPA to increase the efficiency in the use of resources by electric utilities and potentially reduce the price of electricity to consumers.

PURPA's goals of conservation, efficient use of energy resources, and equitable electric rates was also furthered by the concept of "integrated resource planning."[43] 16 U.S.C.A. § 2602(19). Programs related to this concept of integrated resource planning have

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[42] In fact, Section 205 of PURPA authorizes FERC to "exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if [FERC] determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area." 16 U.S.C.A. § 824a-1(a).

[43] The term "integrated resource planning" is defined in PURPA as:

> in the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the project durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

16 U.S.C.A. § 2602(19).

gradually been adopted by the power planning sector and state regulatory bodies, and in 1990, the Massachusetts Legislature further amended G.L. c. 164 to establish an IRM section within the Siting Council.[44] Acts of 1990, c. 150, § 326; G.L. c. 164, § 69H. The IRM section was directed to administer and enforce the Siting Council's IRM regulations "to ensure that [electric] utilities are planning adequately to provide a necessary energy supply for the [C]ommonwealth with minimum impact on the environment at the least possible cost." Id. To ensure that the Commonwealth's utilities were planning adequately to meet this statutory directive, the Siting Council, together with the Department,[45] coordinated the planning process with the review of utilities' procurement and acquisition of energy resources, including the Department's existing PURPA regulatory structure, through the IRM regulations. 980 CMR 12.00; 220 CMR 10.00. The first stage of the four stage IRM process was the Siting Council's review of a utility's long-range forecast.

This coordination between the Siting Council and the Department, for the planning and procurement of energy resources, resulted in a mechanism that provided Massachusetts' electric utilities with a process by which they could identify and plan for their electric needs and requirements and could procure needed resources in an integrated and reviewable manner. This process was created as an integral part of the Siting Council's efforts to provide Massachusetts ratepayers with a necessary energy supply which is reliable, least-cost, and least-environmental-impact. This integrated process was retained in the reorganization of the Siting Council into the Department.

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44 IRM is the functional equivalent of "integrated resource planning."

45 Section 244 of c. 150 of the Acts of 1990 authorized an IRM section within the Department. G.L. c. 25, § 12M. Section 244 directed the Department's IRM section to ensure that electric companies were planning adequately to provide reliable energy from all options, including C&LM and cogeneration. Id.

4. The Reorganization Act

As noted in Section I.A.1, above, effective September 1, 1992, the Siting Council was merged with the Department.[46] The Siting Council, which consisted of ten members[47] was replaced by the Siting Board consisting of seven members.[48] Reorganization Act, § 9; G.L. c. 164, § 69H. Section 12 of the Reorganization Act transferred the review of long-range plans from the Siting Council to the Department. However, the Reorganization Act provided that "a long-range plan submitted in conjunction with a petition to construct a facility may be referred to the [Siting B]oard for review and approval or rejection in accordance with section sixty-nine J." Id. Thus, the IRM process, with this one exception, is now completely overseen by the Department.

The review of petitions for approval to construct power generating facilities was delegated to the Siting Board. Reorganization Act, § 15; G.L. c. 164, § 69J. When a petition to construct a power generating facility is filed by "an electric or gas company which

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46 The Reorganization Act was filed with the General Court by the Governor on May 1, 1992 pursuant to Article LXXXVII of the Amendments to the Constitution and provided for its effective date to be September 1, 1992. Reorganization Act at § 55. Neither the House of Representatives nor the Senate voted to disapprove. An earlier attempt to merge the Siting Council with the Department pursuant to Article LXXXVII was disapproved by the Senate. H. 5013, 1991 Leg., Journal of the Senate, Vol. 29, April 2, 1991, p. 228.

47 The ten members of the Siting Council were the Secretary of Consumer Affairs and Business Regulation, the Secretary of Environmental Affairs, the Secretary of Economic Affairs, the Commissioner of Energy Resources, and six public members including one representing organized labor, one representing environmental concerns, a registered professional engineer, one experienced in matters relating to the electric power industry, one experienced in matters relating to the gas industry, and one experienced in matters relating to the oil industry. The Siting Council was chaired by the Secretary of Consumer Affairs and Business Regulation.

48 The seven members of the Siting Board are the three commissioners of the Department, the Secretary of Environmental Affairs, the Secretary of Economic Affairs, and two public members, one of whom is experienced in environmental or consumer matters and one of whom is experienced in matters relating to the development of energy facilities. The Siting Board is chaired by the Chairman of the Department.

is required to file a long-range forecast pursuant to section sixty-nine I," the Siting Board is required to determine that the facility is consistent with the most recently approved long-range forecast for that company. Id.

The Reorganization Act also provided legislative support for the Siting Council's decisions by noting that the legal and decisional precedents established by the Siting Council "shall continue in force" until such time as they are changed by the newly established Siting Board. Reorganization Act at § 46.

5. Synopsis

As a result of the Legislature's awareness that certain factors were perceived as delaying necessary electric power capacity, the Siting Council was established. As explained by the Siting Commission, the main objectives of the legislation which established the Siting Council were to help eliminate delays as a result of environmental opposition by requiring early public disclosure of plans to expand or construct power facilities, to undertake an adequate consideration of the environment and to establish an appeal process from local regulatory decisions concerning the siting of new power generating facilities. The Siting Council was made responsible for the implementation of these policies, which are contained in G.L. c. 164, §§ 69H to 69S, to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Initially, the Siting Council accomplished these objectives through its review of the long-range forecasts of the electric companies with retail-sales operations in the Commonwealth.[49] These reviews demonstrated that electric companies provided electricity to their ratepayers from self-generation in addition to purchases from facilities both within and without the Commonwealth. The participation of the Commonwealth's electric utilities in the legislatively-approved NEPOOL agreement provided increased reliability to the electric

[49] Jurisdictional utility facility proposals typically were included in long-range forecasts. As noted above, if such a utility proposed a facility in a separate application, the utility had to show that the proposed facility was consistent with the most recently approved long-range forecast.

system through the cooperation and joint participation in the development of a bulk regional power supply system.

This regional power supply system was provided with additional power generation options through the enactment of PURPA. PURPA, whose purpose was to encourage conservation, optimization of efficiency in the power generation market and equitable rates for electric consumers, opened the power generation market to non-utility developers. As a result, the Siting Council found it necessary to adapt its review processes to fulfill its statutory mandate while reviewing the plans of non-utility developers who opted to construct power generating facilities in the Commonwealth.

Finally, the review of long-range forecasts of electric companies, including IRM reviews, was moved under the authority of the Department pursuant to the Reorganization Act, which merged the Siting Council into the Department. The Reorganization Act, however, assigned the review of proposed energy facilities to a newly constituted, autonomous Siting Board. In addition, the Reorganization Act specifically approved the Siting Council's body of precedent, which had developed over the years to reflect the changing nature of the electric power generating market in response to both state and federal legislation. It is this legislative history that the Siting Council, through its review of proposals to construct jurisdictional facilities by non-utility developers, has attempted to satisfy through the development of its standards of review for jurisdictional facilities.

II. ANALYSIS OF THE PROJECT[50]

A. Introduction

As noted in Section I.B.1, above, the Siting Council's enabling statute contemplated the construction of power generating facilities by electric utilities who were required to file long-range forecasts. PURPA, however, provided the opportunity and incentive for the development of a market for the power from generating facilities constructed by non-utility developers. As the Legislature had not envisioned proposals to construct such facilities outside the format of a long-range forecast, the Siting Council's enabling statute was silent as to how specifically such a petition should be handled.[51] Thus, on June 22, 1987, when Northeast Energy Associates ("NEA"), the first non-utility developer to petition the Siting

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50 The Siting Council separated its reviews of proposals to construct facilities into two stages. In the first stage, the "project-level" review, the Siting Council analyzed: (1) the need for additional energy supplies and whether the proposed project could meet that need; (2) the relative costs and environmental impacts of the proposed project and alternatives capable of meeting the identified need; and (3) the likelihood that the proposed project would be viable. It is the second issue on alternatives which the Siting Council eliminated prior to the review of EEC's petition which is the primary focus of the Court's remand. In a second stage of its analysis, the "facility-level" review, the Siting Council analyzed proposed facilities with regard to the site-selection process used by the proponent and the cost, environmental and reliability impacts of the proposed facility at the proposed and alternative sites, in order to ensure that the facility would minimize environmental impacts consistent with minimizing cost.

This two-stage analysis is strictly organizational in nature. Both stages address issues contained in Sections 69H and 69I. The terms "proposed project" and "proposed facility" are used in the Siting Board's decisions for convenience and their use is not intended to imply that the Siting Board's jurisdiction goes beyond the review of facilities as that term is defined in G.L. c. 164, § 69G.

51 The Siting Council notes that the Legislature acknowledged this distinction and indicated its intent that the statute would apply to non-utility developers when it enacted Section 69J1/2 of G.L. c. 164. The filing fees that were required by that section were to be imposed on non-utility developers rather than on utility companies subject to an annual assessment by the Siting Council. G.L. c. 164, § 69J1/2. Similarly, the review schedules for applications from utilities was different than that for non-utility developers. Id.

Council for approval to construct a jurisdictional power generating facility, filed its petition, the Siting Council, required by G.L. c. 164 to review proposed power generating facilities of 100 MW or greater, was faced with the need to glean from its statute a review process that would endeavor to fulfill the Legislature's intent in its enactment. The NEA Decision, issued December 18, 1987, was the Siting Council's first attempt to achieve this goal.

In considering the differences between utility and non-utility proposals which were relevant to Siting Council review, three major distinctions arose. First, since a non-utility developer has no established market area and would have no previously approved long-range forecast for such a market area, the Siting Council could make no determination as to whether a proposed non-utility project was consistent with such a forecast.[52] Second, a non-utility developer proposes to construct a specific project to sell electric power at wholesale to electric utilities, thereby competing in the power sales market unlike a utility which selects among alternatives to meet its identified need for additional resources. Thus, the non-utility developer is not selecting from a full range of alternatives to meet a specified need and the Siting Council is unable to review a proposed non-utility project in such a

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[52] As noted above, prior to enactment of the Reorganization Act, the requirements to approve an energy facility were contained both in G.L. c. 164, §§ 69I and 69J. Approval was conditioned on consistency between the proposal to construct an energy facility and the most recently approved long-range forecast of needs and requirements for the market area of the electric company submitting the forecast. G.L. c. 164, § 69J. The long-range forecast was to be approved if it complied with the requirements of sections 69I and 69J including that it be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Id. The Siting Council determined, therefore, that electric companies that were not required to file long-range forecasts, i.e., non-utility developers, nevertheless could receive approval of a petition to construct an energy facility if approval was conditioned on consistency with the appropriate requirements of sections 69I and 69J including that it be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

context.[53] Third, as a non-utility developer is not guaranteed a rate of return, there is no guarantee that a proposed project will be viable as a least-cost resource over the life of a contract, whereas a utility, which has a regulated rate of return, has a high likelihood of viability over the life of the project. See Section II.B.2, below. These three distinctions, therefore, required the Siting Council to adapt its standards for the project-level review of proposals by non-utility developers from those used in the review of utility proposals to construct facilities.[54] In so doing, the Siting Council established procedures for the review of proposals by non-utility developers outside the context of a long-range forecast review.

In the EEC Decision, the Siting Council made findings on all project-level issues including need, project approach,[55] and viability consistent with the Siting Council's then current standard of review. However, at that time, the standard of review for non-utility developers did not require a comparison of alternatives. It is specifically the issue of a comparison of alternatives that the Court remanded the decision to the Siting Council to revisit, although the Court also expressed concern with the adequacy of the Siting Council's findings on need. Therefore, as noted above in this decision, the Siting Board conducts a review of alternatives to the proposed project and reanalyzes the need for the proposed

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[53] In the review of a proposed utility project, the utility would have to establish that its proposed project was the best alternative through the review of its most recent long-range forecast and supply plan. As noted above, utilities are required to provide information on alternatives to their planned actions. G.L. c. 164, § 69I. Thus, through the review of a utility's long-range forecast and supply plan, the Siting Council could determine whether there was a need for the proposed project and whether the utility had chosen the best available alternative to meet that need. The prohibition on construction contained in G.L. c. 164, § 69J unless a proposed facility is consistent with the most recently approved long-range forecast, shows the Legislatures' intended connection between the utilities forecast of need and resource selection process and approval of a proposed project.

[54] The balance of the review, i.e., the facility-level review, is basically identical between proposals by utility and non-utility developers.

[55] The project approach review in the EEC Decision consisted of an analysis of the proposed project's consistency with the resource use and development policies of the Commonwealth. 22 DOMSC at 285-295.

project. As noted in Section I.A.5, above, in light of the Court's directives the Siting Board must, as an initial matter revisit the development of its standards. Therefore, the Siting Board will start with a review of the evolution of its standard, then note the Court's directive and proceed through a statement of the arguments of the parties, an analysis of the arguments, and the development of a standard of review for use in this and future cases based on the foregoing. The Siting Board will undertake this review for both the comparison of alternatives and the updated review of need.

B. Alternative Technologies Comparison[56]

1. The Development of the Siting Council's Standard of Review for Non-Utility Developers

In the development of its standard of review for alternatives to the propose project in the NEA Decision, the Siting Council first reviewed its earlier decisions relative to utility plans to construct jurisdictional electric transmission lines and gas pipelines.[57] NEA Decision, 16 DOMSC at 345. The Siting Council noted the directive of G.L. c. 164, § 69H which required the Siting Council to evaluate proposals to construct energy facilities in terms of their consistency with providing a necessary energy supply for the Commonwealth with a

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56 In past decisions, the Siting Council addressed the analysis of need, and specifically, the need for a proposed project, as an initial matter. The Siting Council reasoned that if need could not be established, no further analysis of a proposed project would be required. Nevertheless, in light of the remand of the EEC Decision for a comparison of alternative energy resources, this decision will first address the issue of the alternative technologies comparison. To do so, the Siting Board presumes that 300 MW of additional electric power are necessary for the Commonwealth for reliability or economic efficiency reasons. In Section II.C, below, the Siting Board will address need based on the record as updated by the proceedings on remand.

57 The Siting Council was also guided by the requirements of G.L. c. 164, § 69I relative to the information required for the siting of oil facilities, the only comparable, non-utility facilities governed by the Siting Council's enabling statute. See, Section I.B.1 and n.30, above. Thus, the Siting Council incorporated the requirements of Section 69I, e.g., project viability, the applicant's qualifications and capability to provide reliable energy resources, and mitigation measures to minimize damage to the environment from the proposed facility, into its review of petitions to construct bulk generating facilities by non-utility developers.

minimum impact on the environment at the lowest possible cost. Id., 16 DOMSC at 360. The Siting Council further noted that in implementing this statutory mandate in previous reviews of proposed utility company facilities, the Siting Council had required the companies to show that their proposed projects were superior to alternatives in terms of cost and environmental impact for meeting an identified need. Id., 16 DOMSC at 360-361. Thus, the Siting Council determined that a review of a petition to construct an energy facility by a non-utility developer would require the same balancing of environmental impacts and cost considerations, and, therefore, a developer of a QF also was required to demonstrate that its proposed facility was superior to alternatives in terms of cost and environmental impacts in meeting the identified need for additional power resources. Id., 16 DOMSC at 363. The Siting Council stated that as a part of this balancing test a developer of a QF must show that the proposed project is financially viable, i.e., that the proposed project would operate and produce needed energy benefits.[58] Id., 16 DOMSC at 363-364.

Therefore, in reviewing proposals of non-utility developers, the Siting Council concluded that it must determine whether the proposed project: "(1) is superior to a range of practical alternatives in terms of cost; (2) offers power at a cost below the purchasing utility's avoided cost; (3) is superior to alternatives in terms of environmental impacts; and (4) is likely to be viable as a source of energy over time." Id., 16 DOMSC at 364. Finally, the QF must show that, on balance, the proposed project is consistent with ensuring a necessary energy supply with a minimum impact on the environment at lowest possible cost. Id.

NEA provided an analysis comparing its proposed project to various generic alternative generating options. Id., 16 DOMSC at 369, 375. Resource options that were either too

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[58] As noted above, G.L. c. 164, § 69J requires the consideration of such viability questions in the review of a notice of intention to construct an oil facility. The Siting Council, aware that a QF developer, unlike a utility, is not guaranteed a rate of return on its activities generally, thus, required such developers to establish that their projects would be (1) reasonably likely to be financed and constructed, and (2) likely to operate and be a reliable source of energy over the life of their power sales agreements, before issuing an approval. See NEA Decision, 16 DOMSC at 380.

costly, not mature, or that had fuel-supply constraints were eliminated from the comparison, and fuel and technology options were ranked in terms of their environmental attributes in order to screen options that were not technologically or environmentally feasible. Id., 16 DOMSC at 369-370, 376. After calculating costs on a levelized basis, NEA compared its proposed project to the remaining alternatives. Id., 16 DOMSC at 370, 376. Based on the record developed in the NEA proceeding, the Siting Council concluded that NEA had demonstrated that its proposed project satisfied each of the four elements of the project-level review. Id., 16 DOMSC at 375, 378, 380. Accordingly, the Siting Council found that NEA's proposed project was consistent with ensuring a necessary energy supply with minimum impact on the environment at lowest possible cost. Id., 16 DOMSC at 380. On December 18, 1987, the Siting Council issued the NEA Decision, in which it approved the proposed project subject to two conditions related to environmental mitigation.

In February, 1988, the Siting Council received its second petition to construct a bulk generating facility by a non-utility developer from Altresco-Pittsfield, Inc. ("Altresco"). A third petition to construct a bulk-generating facility was filed on March 8, 1989, by MASSPOWER, Inc. ("MASSPOWER").[59] The Siting Council's methodology for the comparison of alternatives remained unchanged in the review of these two petitions. In each case, after comparing the proposed project to the alternatives identified in that case, the Siting Council found that the proposed project was superior to the identified alternatives in terms of cost and environmental impact. MASSPOWER Decision, 20 DOMSC at 341, 348; Altresco Decision, 17 DOMSC at 374, 377. However, in the MASSPOWER Decision, the Siting Council expressed concerns about continuing to employ an analysis of alternatives based exclusively on a comparison of generic technologies. 20 DOMSC at 349.

The Siting Council noted that, in the earlier non-utility petitions that had been reviewed, the evaluation of the petitions focussed on a comparison of the applicant's proposed generating technology and other generic generating technologies capable of

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59 The Siting Council issued its Altresco Decision on August 4, 1988, and its MASSPOWER Decision on August 10, 1990.

delivering the necessary energy resources. Id. Such a technology-based evaluation was somewhat incompatible with the Siting Council's reviews of utilities proposing to construct energy facilities. Id., 20 DOMSC at 350. A review of a proposal filed by a utility would require the Siting Council to determine whether the proposed utility project was consistent with the utility's most recently approved forecast of needs and requirements for its market area. G.L. c. 164, § 69I. Thus, the plan to construct the proposed facility would have to be consistent with the "description of actions planned to be taken by the utility which will affect capacity to meet such needs or requirements, including ... a description of alternatives to planned action." Id. Thus, as noted above, the Siting Council was able to determine whether the utility's proposed project was selected after a comprehensive evaluation of resource options available to the utility, and represented the least-cost, least-environmental-impact approach available to the utility. MASSPOWER Decision, 20 DOMSC at 350.

The Siting Council stated that a utility must meet the discrete and finite needs of its customers as it has an "obligation to serve" those customers. Id. Further, a utility can meet its obligation with a full range of resources that are available to it.[60] Id. In contrast, a non-utility developer has neither the obligation to serve nor the access to a full range of resources available to meet that obligation. Id., 20 DOMSC at 351. Thus, while the non-utility developer must show that there is a need for its proposed project, the Siting Council noted that it would be inappropriate to require a non-utility developer to establish that it had selected a superior project from a full range of resource options, many of which are not available to that developer.[61] Id.

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60 For example, a utility can increase its delivery of Conservation and Load Management ("C&LM"), can build small generating facilities if additional load requirements are small, or purchase power from other utilities or non-utility developers located in-state or in neighboring states or regions.

61 In addition, the Siting Council was aware that options available to different utilities vary due to the nature of their existing resource mix. Thus, without knowing which utility would purchase the power from a proposed non-utility project, the Siting Council had no basis upon which to weigh the criteria to determine whether a proposed (continued...)

The Siting Council acknowledged, however, that the fact that the non-utility developer does not have access to a full range of resource options, does not mean that the Siting Council was any less committed to ensuring that a proposed project by a non-utility developer is superior to alternatives in terms of cost, environmental impact, reliability, and meeting the identified need. Id. In terms of cost, the Siting Council noted that the then current cost test -- the requirement that a non-utility developer establish that its proposed project offers power below purchasing utilities' avoided costs -- would remain unchanged.[62] Id. However, in future cases, the Siting Council stated that it would formulate a new standard which would "attempt to find mechanisms which (1) allow us to compare proposals by non-utility developers with a full range of resource options available to the state and region, and (2) place greater emphasis on determining whether a non-utility developer's proposed project is consistent with our statutory mandate and the resource use and development policies of the Commonwealth.[63] Id., 20 DOMSC at 351-352.

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[61](...continued)
project was superior to other alternatives. As directed by the Court, the Siting Board will compare alternative resource options in this and future reviews of applications to construct power generation facilities. Nevertheless, the Siting Board will continue to require utilities to analyze proposed new facilities against a full range of resource options that are available to it, as required by G.L. c. 164, § 69J.

[62] As MASSPOWER did not have any signed and approved PPAs, it could not compare its costs to the avoided costs of the utilities with whom it had contracted as was done in the previous non-utility facility cases. Rather, MASSPOWER presented a 20-year projection of its power costs compared to a similar projection based on the avoided costs of several individual utilities, using comparable escalation rates in both. MASSPOWER Decision, 20 DOMSC at 341-342. The Siting Council accepted this methodology as a valid proxy to establish that a proposed project offers power below purchasing utilities' avoided costs. Id. at 342.

[63] In emphasizing resource use and development policies of the Commonwealth, the Siting Council was recognizing the directive of G.L. c. 164, § 69J which requires that "plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth." In earlier decisions, the Siting Council had not explicitly addressed this statutory requirement.

The MASSPOWER Decision was issued prior to the commencement of evidentiary hearings on the petition of West Lynn Cogeneration ("West Lynn"), the fourth non-utility petition to construct a bulk generating facility filed with the Siting Council.[64] Consistent with the Siting Council's directive in the MASSPOWER Decision, the new standard was first applied in the decision on West Lynn's petition.[65] In the West Lynn Decision, the Siting Council reiterated its rationale for adopting a new standard,[66] and then reviewed West Lynn's position as to what this new standard should be. Id., 22 DOMSC at 57. The Siting Council then adopted its new standard relative to the project-level review of a proposed non-utility facility which incorporated the following components:

-- in the Need Analysis (see Section II.C, below), proposed projects would have to meet a Massachusetts benefits test to ensure that the proposed project would provide reliability, economic and/or environmental benefits to the Commonwealth in sufficient magnitude to offset the impacts on the Commonwealth's resources of construction and operation of such a facility;

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64 West Lynn filed its petition with the Siting Council on April 11, 1990. The Siting Council issued its West Lynn Decision on June 14, 1991.

65 In addition to notifying the parties in the West Lynn proceeding of the intent to formulate a new standard of review, the Siting Council notified the parties in the EEC proceeding and the Enron Power Enterprises Corporation ("Enron") proceeding, both of which were before the Siting Council at that time. Enron's petition was filed with the Siting Council on April 6, 1990. All three applicants had filed their petitions based on the Siting Council's standards found in the NEA Decision and the Altresco Decision.

66 The Siting Council also raised the additional point that the standard used in the first three non-utility power generation facility reviews ignored a fundamental tenet of utility least-cost supply planning which requires a full understanding of the utility's existing resource mix, real alternative resource options and customer base. West Lynn Decision, 22 DOMSC at 57. Without this knowledge, a proposed project could be rejected on the basis of the Siting Council's traditional generic technology comparison when, in fact, it might have been the most appropriate resource addition for a particular utility. Id.

-- proposed projects would be compared to a complete menu of uncommitted resource options available to the state and the region which are reasonably likely to be available to meet the identified need within the necessary time frame, and represent the least-cost, least-environmental-impact resource for each utility through the review of each utility's supply planning process pursuant to the IRM regulations of the Siting Council and the Department;

-- proposed projects would have to pass a viability test to ensure that they will provide the region with a least-cost, reliable energy resource over the life of its PPAs;

-- greater emphasis would be placed on whether a proposed project is consistent with the resource use and development policies of the Commonwealth, in particular to those policies which relate to energy, environmental and economic impacts;[67] and

-- the review of cost and environmental impacts of the proposed facility and the proposed and alternative sites would continue to be analyzed in the facility-level review. Id., 22 DOMSC at 58-60.

In the West Lynn Decision, the Siting Council noted that its intent was not to retreat "from its commitment to a project-level analysis or from its statutory commitment to ensure a least-cost, least-environmental-impact energy supply for the Commonwealth." 22 DOMSC at 59. Rather, the Siting Council noted that other aspects of the review of a non-utility developer's petition comprehensively addressed specific cost, environmental and reliability characteristics of proposed projects.[68] Id.

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67 The Siting Board notes that the requirement for plans for expansion and construction of an applicant's new facilities to be consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth has been addressed in n.28 and n.63, above.

68 The Siting Council explained that: (1) the Massachusetts benefits analysis addresses whether construction and operation of a proposed project will provide reliability, economic and/or environmental benefits to the Commonwealth; (2) the viability analysis ensures that the proposed project will provide a least-cost energy resource and offer power below purchasing utilities' avoided costs; and (3) the facility-level review addresses cost and environmental impacts of the proposed facilities. West Lynn Decision, 22 DOMSC at 59, and n.30.

Through the adoption of this new standard of review, the Siting Council addressed the concerns it had raised in the MASSPOWER Decision. Rather than comparing a proposed project with real costs and environmental impacts to theoretical projects with estimated costs and environmental impacts based on generic information, a proposed project would be compared to the real alternative resource options available to the state and the region on a utility by utility basis through the IRM process. Such uncommitted resource options would be restricted to only those options that would reasonably be likely to contribute to meeting an identified need as opposed to options that might not be able to be financed, permitted or built. This approach placed the comparison of alternatives back in individual utility's supply plan reviews as originally envisioned by the statute, and thereby placed responsibility for alternative resource decisions on utilities who have an obligation to serve. Further, as IRM was the Siting Council's regulatory framework for the review of long-range forecasts and supply plans of utilities, the Siting Council would have been, in effect, relying on its own decisions in those forecast and supply plan cases. In all other major respects, this new standard of review was comparable to the earlier project-level review that had been used by the Siting Council in previous utility and non-utility facility reviews.

The petition of EEC, therefore, was the second non-utility facility review in which this new standard was applied. In response to comments of the parties to the EEC proceeding relative to the new standard, the Siting Council further refined the issues that would need to be addressed in the project-level review of a non-utility developer's petition to construct a bulk generating facility. The Siting Council agreed with the Attorney General, who argued that it would be inappropriate for the Siting Council to identify specific resource options for comparison to a proposed facility. EEC Decision, 22 DOMSC at 282. The Siting Council noted, however, that regardless of who identified specific resource options, comparisons of proposed projects to specific alternatives was problematic in the review of a non-utility developer. Id.

In response to further arguments of the parties, the Siting Council noted that the standard of review used in earlier reviews failed to provide a level playing field for utility and non-utility proposals.[69] Id. Thus, the Siting Council maintained that it was inappropriate to require a non-utility developer to establish that its proposed project was superior to a full range of resource options when the non-utility developer only had access to its own option. Id. Similarly, the Siting Council rejected the notion that non-utility developers should be required to compare their proposed projects to real and generic alternatives. Id., 22 DOMSC at 283. The Siting Council noted that it would be difficult and costly to acquire information on the large number of potential and planned projects partly due to the fact that much of the specific information associated with such projects is confidential. Id. Further, comparisons of real proposals to generic projects retained the problem that real costs and environmental impacts would have to be compared to hypothetical costs and environmental impacts, in addition to ignoring site-specific characteristics. Id.

The Siting Council also rejected the argument that non-utility developers should be required to demonstrate that comprehensive C&LM policies have been implemented, noting that it would be impractical for non-utility developers to monitor utility C&LM plans and proposals. Id. Rather, the Siting Council determined that, consistent with the statutory directive of G.L. c. 164, § 69J[70] to adequately consider C&LM in the projections of demand for electric power, the proper place for an analysis of C&LM should be in the analysis of need. Id.

The Siting Council also rejected the establishment of a set of pre-approved generic technologies for purposes of comparison to proposed projects. Id. The Siting Council noted that such a process retained the same flaws as the generic alternative technologies comparison rejected by the Siting Council in the MASSPOWER Decision. Id., 22 DOMSC at 283-284.

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69 As noted above, in the case of a utility that was proposing to construct an energy facility, the comparison of alternatives would take place in the review of the utility's resource acquisition process during the IRM review.

70 This statutory directive was located in G.L. c. 164, § 69J at the time of the review of EEC's petition. The current version of G.L. c. 164 retains this identical language in both section 69I relative to the review of utility long-range forecasts and section 69J relative to the review of applications to construct energy facilities.

In addition, the Siting Council found the various suggestions to find certain types of facility proposals, fuels, resource options and technologies as generally preferable or generally acceptable as incompatible with reviewing proposed projects in light of a full array of resource options, and the resource use and development policies of the Commonwealth. Id., 22 DOMSC at 284.[71]

The petition of Enron, as noted above, was also pending at the time of the West Lynn Decision. The Enron Decision is the most recent non-utility facility review that was completed by the Siting Council.[72,73] As the Enron proceedings were in process at the time of the issuance of the West Lynn Decision, the parties in the Enron proceedings were also afforded an opportunity to address the Siting Council's new project-level standard of

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71 The Siting Council then reviewed the consistency of EEC's proposal with the resource use and development policies of the Commonwealth and found that the proposed project was consistent with the policies encouraging the development of cogeneration facilities, was not inconsistent with state policies encouraging C&LM, and was consistent with broad energy policies related to diversity of energy resources. EEC Decision, 22 DOMSC at 286, 287, 295. Accordingly, the Siting Council found that EEC had established that its proposed project approach would be consistent with the broad resource use and development policies of the Commonwealth. Id., 22 DOMSC at 295.

With regard to viability, the Siting Council found the proposed project reasonably likely to be financed and constructed and likely to operate as a reliable, least-cost energy supply and conditioned a final finding on viability on the production of specific, appropriate written agreements. Id., 22 DOMSC at 312.[71]

72 The Siting Council issued its Enron Decision on August 29, 1991.

73 At the time of the Court's decision in City of New Bedford, the Siting Council was in the process of reviewing three additional petitions to construct bulk generating facilities by non-utility developers: Silver City Limited Partnership; Cabot Power Corporation; and Altresco Lynn, Inc. Hearings have been concluded and briefs have been filed in all three of these proceedings. Tentative Decisions will follow the resolution of the issues raised in City of New Bedford in the decision on remand in the present case.

review. In response to the suggestions of Enron,[74] the Siting Council noted that the first part of Enron's three-part suggested approach generally conformed to the standard adopted by the Siting Council in the West Lynn Decision and followed in the EEC Decision regarding consistency of a proposed project with the resource use and development policies of the Commonwealth. Enron Decision, 23 DOMSC at 83. The Siting Council rejected the second part of Enron's proposal which relied on consistency of a proposed project with the electric utility supply plans of electric utilities that would be purchasing from the proposed project because such supply plans are extremely utility-specific and the planning criteria set forth in such a supply plan cannot be considered to be a proxy for a determination of consistency with current state resource use and development policies. Id., 23 DOMSC at 84. The Siting Council also rejected the third part of Enron's proposal as it appeared to duplicate portions of the Siting Council's viability analysis.[75] Id.

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74 Enron proposed a three-part project approach. Enron Decision, 23 DOMSC at 83. Specifically, Enron's proposed standard would require a determination: (1) of whether the proposed project is consistent with state or regional policies regarding the need for resources, cost of various options, diversity of resources, consistency of environmental objectives, and other policy goals; (2) of whether the proposed project is consistent with the least-cost planning criteria and objectives of purchasing utilities, such as diversity of supply, lower economic cost, minimization of environmental impacts, and rate stability; and (3) that the proposed project is reasonably competitive against "like kind" projects in terms of cost, reliability, viability, and other factors. Id., 23 DOMSC at 78-79.

75 The Siting Council then reviewed the consistency of Enron's proposal with the resource use and development policies of the Commonwealth and found that the proposed project: (1) was consistent with energy policies related to diversity of energy resources; (2) was not inconsistent with the Commonwealth's current economic policies; (3) would not be inconsistent with the development of QFs; and (4) was generally consistent with the current environmental policies of the Commonwealth. Enron Decision, 23 DOMSC at 87-88. Accordingly, the Siting Council found that Enron had established that its proposed project approach was consistent with the broad resource use and development policies of the Commonwealth. Id., 23 DOMSC at 89.

With regard to viability, the Siting Council found the proposed project reasonably likely to be financed and constructed and likely to operate as a reliable, least-cost
(continued...)

As noted above, in light of the Court's Decision in City of New Bedford, the Siting Board must revisit the project-level standard of review developed in the Siting Council cases. Thus, the Siting Board will next review the Court's directive and the arguments of the parties. The Siting Board will follow this with the establishment of a new standard of review for energy facilities proposed by developers who are not required to file a long-range forecast, for this and future cases. Finally, the Siting Board will evaluate the proposed EEC project in light of this new standard of review.

2. Standard of Review after City of New Bedford

a. The Court's Directive

In City of New Bedford, the Court noted that the Siting Council's enabling statute "mandates that the council 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. The Court explained that to perform that balancing, the Siting Council "must evaluate whether the *minimum impact* standard has been met." Id. The Court noted that the Siting Council's analysis included a showing: (1) of need for additional energy resources; (2) that the proposed project was consistent with the resource use and development policies of the Commonwealth and a viable source of energy over time; and (3) that the site selection process had not overlooked or eliminated clearly superior sites and that the proposed site was acceptable in terms of cost, environmental impact and reliability of supply. Id. at 486. The Court rejected the Siting Council's analysis noting that "minimizing or reducing the environmental impact of a particular project is not the equivalent of determining that the project will impart a minimum impact on the environment."[76] Id. at 488. The Court then concluded that "[i]t is logically impossible to

[75](...continued)
energy supply and conditioned a final finding on viability on the production of additional, specific documentation. Id., 23 DOMSC at 105, 119.

[76] In the EEC Compliance Decision the Siting Council concluded that the proposed facility, if constructed according to the directives contained therein would accomplish a least-cost, least-environmental-impact CFB facility.

conclude that a particular power plant produces the least possible -- and hence minimum -- impact on the environment without comparing such plant with other energy resource alternatives." Id.

In light of the Court's directive, the Siting Board must now proceed to analyze whether the "minimum impact" standard has been met, after comparing the proposed project with other energy resource alternatives. As noted in Section I.A.4, above, (see n.12 and accompanying text) the Siting Council's past approach compared proposed projects to generic resource alternatives. City of New Bedford, 413 Mass. at 485. In the next section, the Siting Board sets forth and analyzes the approaches suggested by EEC and by the Attorney General in response to the Court's directive. The Siting Board conducts a comparison of the proposed project and alternatives in Sections II.B.3 - 7, below.

b. Positions of the Parties[77]

i. The Company's Position

The Company argued that the Siting Board's enabling legislation "sets forth broad policy direction and factors for the Siting Board to consider" (EEC Brief at 76). EEC asserted that G.L. c. 164, § 69J establishes detailed filing requirements for petitions to construct energy facilities and enumerates the factors the Siting Board must consider in order to approve a petition to construct such a facility[78] (id.). The Company explained that the Siting Board's mandate "to provide a necessary energy supply for the [C]ommonwealth with a minimum impact on the environment at the lowest possible cost," requires the Siting Board to balance three criteria (id. at 77). These three criteria are: (1) the necessity of reliable energy supplies; (2) the cost of the proposed project; and (3) the environmental impact of the proposed project (id.).

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77 Arguments as to the appropriate standard of review for the Siting Board to use in its analysis of alternatives were presented only by the Company and the Attorney General.

78 The Siting Board notes that EEC appears to be referencing the latest version of G.L. c. 164. The Reorganization Act clarified the requirements of petitions to construct energy facilities and the factors to be considered by the Siting Board in the review thereof. See n.25 and Section I.B.4, above.

EEC cited the Court's support for the premise that the Siting Board is required to balance these three statutory objectives (id. at 78, citing, City of New Bedford, 413 Mass. at 485). EEC maintained that the Siting Board, therefore, is to apply its expertise in balancing the conflicting objectives of these three criteria when considering new facilities (id. at 77). Further, EEC argued that the Court approved the Siting Board's authority to determine that "other factors" could outweigh environmental impacts of a proposed facility, but that the Siting Board must include a statement of reasons that includes a determination of each issue of fact or law necessary to the decision (id. at 78, citing, City of New Bedford, 413 Mass. at 490).

EEC asserted that the Court endorsed the standard of review that the Siting Council used in the MASSPOWER Decision and asserted that "this standard fully meets the requirements of the statute"[79] (id. at 79). Thus, EEC argued that the Siting Board should adopt a standard of review similar to that used in the MASSPOWER Decision (id. at 79-83). EEC asserted that the elements of such a review, following a finding of need for the proposed project and the superiority of the proposed site, would include identifying the alternative technologies that could be built on the proposed site that could fulfill the need, eliminating any comparison of options that could not meet the need, and then using

79 EEC maintained that, in all respects other than the analysis of alternatives, the EEC Decision used the same standards as the MASSPOWER Decision. EEC Brief at 80. Thus, with regard to projections of need, the effect of C&LM, the finding that the site-selection process demonstrated the proposed site was superior to alternatives, and the requirement to provide comprehensive environmental studies on specific statutorily listed environmental impacts, EEC argued that the EEC Decision complied with the statute and the Court's directive. Id. at n.80. EEC also noted that the MASSPOWER Decision did not require a finding of consistency with current health, environmental protection, and resource use and development policies of the Commonwealth, but that G.L. c. 164, § 69J requires their consideration and urged the Siting Board to make appropriate findings based on the record evidence already submitted. Id.

project-specific and site-specific data to compare the proposed facility with the range of other practical generating alternatives[80] (id. at 80-81).

In response to arguments raised by the Attorney General, EEC maintained that the Siting Council, in the EEC Decision, had already dismissed the argument that externality values should be added in the cost comparison of alternatives (EEC Reply Brief at 53-54). In addition to the Siting Council's reasons for rejecting the use of these values, the Company noted that to incorporate the values in the cost analysis as well as comparing environmental factors of alternatives would amount to double counting of the values (id. at n.37). The Company also argued that to focus exclusively on the quantity of emissions and volume of use rather than on their environmental impacts ignores the statutory mandate relative to the minimum impact standard (id. at 55-56). EEC argued that the Siting Board should first determine "whether each emission or volume of use amounts to an environmental impact and, second, how that impact, if any, compares to the impacts of the other alternatives" (Id. at 56).

ii. The Attorney General's Position

The Attorney General argued that the Court's decision in City of New Bedford explicitly found that the Siting Board's enabling legislation directs the Siting Board to balance the environmental harm of a new power plant with the other statutory objectives of providing a necessary energy supply at the lowest possible cost (Attorney General Brief at 96-97). The Attorney General also argued that the Court found that the Siting Council's past practice of requiring a non-utility applicant to establish that its proposed plant was superior to alternative approaches in terms of cost, environmental impact, reliability and ability to address a

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80 EEC explained that looking only at those options that can meet the identified need is consistent with G.L. c. 164, § 69J which requires "a description of actions planned to be taken by the applicant to meet future needs or requirements" (EEC Brief at 81). Further, the Company asserted that project-specific comparisons are also consistent with the same section of the statute which requires comparison of alternatives "to the 'planned action', i.e., the proposed facility" (id.). In addition, EEC argued that the Siting Board cannot perform its statutorily mandated balancing of reliability, cost and environmental impacts without reviewing those criteria as they will be affected by the proposed site (id. at 81-82).

demonstrated need comported with the statutory mandate (id. at 97). The Attorney General further argued that the Court's decision clarified that both utility and non-utility applicants must comply with the statute's requirements (id. at 97-98). In short, the Attorney General concluded that in all siting cases, "a full comparative review of the environmental consequences, relative benefits, and feasibility of using alternatives to any plant proposed by a developer" must be undertaken (id. at 98).

The Attorney General maintained that G.L. c. 164, § 69I provides that this comparative review requires, among other things, a description of alternatives to the planned action including "no additional electrical power or gas; [and] a reduction of requirements through load management" (id.). The Attorney General also maintained that that section lists additional data which must be provided relative to impacts of the planned action (id.). Relying on the MASSPOWER Decision, the Attorney General explained that a comparison of alternative approaches that are comparable in terms of their ability to meet the established need must first analyze the proposed project's environmental impacts after which the Siting Board "may then balance the adverse environmental harm that would be caused by the new power plant against other permissible minimum impacts" (id. at 99). The plant can then be approved if the Siting Board finds that the impacts from the proposed plant are minimum, or, if they are not, that the adverse impacts are outweighed by other permissible goals of the statute (id.).

The Attorney General argued that G.L. c. 164, § 69I requires all project proponents to evaluate the possibility of meeting demonstrated need through means other than new power generation (id.). Thus, the Attorney General argued that new power needs first should be measured against available conservation and a non-utility developer should be required to demonstrate that energy savings equivalent to the new capacity that its proposed project would provide cannot be provided through C&LM[81] (id. at 100).

81 The Attorney General argued that the fact that a non-utility developer might not be in a position to deliver C&LM should not be an excuse for failing to undertake to study and describe the current and future reach of conservation programs (Attorney General Brief at 100).

The Attorney General argued that if C&LM is incapable of meeting the demonstrated need, the Siting Board should then consider a hierarchy of other options (id. at 101-102). The Attorney General asserted that these other options should commence with renewable resources that are cleaner than fossil fuels, and then proceed through natural gas options and coal gasification options, both of which are superior to the proposed CFB option (id.).

The Attorney General also argued that the Siting Board should require proponents of new facilities to compare their proposed project to real project alternatives, not to generic alternatives (id. at 102-103). The Attorney General maintained that, "[i]n most cases, the proponents are sophisticated, experienced actors in the power generation field who have as much knowledge as anybody about the availability and technical details of the full panoply of energy resource options" (id. at 103). The Attorney General also maintained that the Siting Board should not ignore other projects that are currently being reviewed in separate dockets before the Siting Board as examples of other real alternatives (id. at 104). The Attorney General concluded that "[w]henever a real project exists that can be made the basis for an alternatives comparison, it should be required to be so utilized. In such a situation, a 'generic' review should be deemed insufficient per se" (id.).

The Attorney General further argued that the Siting Board, when balancing environmental impacts and cost, should include in the consideration of costs the environmental externality costs found in the Department's IRM regulations (id. at 105-106). The Attorney General asserted that in addition to being a part of the total cost of the project, such a comparison would bring consistency to the resource development and resource acquisition phases of providing energy resources[82] (id. at 106). To the extent that non-price criteria must be weighed against considerations of externalities, the Attorney General cited

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82 The Attorney General acknowledged that the Department's values for externalities only apply to air pollutants and are, therefore, underinclusive (Attorney General Brief at 108). Nevertheless, he argued that the Siting Board should include the values that currently exist and expand coverage to all significant environmental externalities that the Department later monetizes (id.).

the Siting Council's decision in EFSC 90-RM-100A,[83] for the proposition "that consideration of externalities are not to be overridden by non-price criteria, such as fuel diversity"[84] (id. at 108-109).

The Attorney General argued that the principal goal of the IRM regulations is to level the playing field in the acquisition process and the same should be required in the resource development process (id. at 107). The Attorney General also argued that G.L. c. 164 does not treat non-utility developers and utilities differently, therefore, the Siting Board should not do so in the siting process (id.). The Attorney General further argued that since the Siting Board has expressed its belief that the IRM process is an efficient process for fulfilling its statutory mandate, adopting the Department's externalities values for non-utility developers in the siting review process would be the most sensible approach for the Siting Board (id. at 110).

In response to an argument raised by EEC, the Attorney General argued that EEC has acknowledged the externalities values in its brief and attempts to benefit from the authorization of the Department to use emission offsets to reduce total emissions[85] (Attorney General Reply Brief at 13). The Attorney General argued that EEC is attempting to take advantage of the emissions offsets, thereby reducing its total emissions, but ignoring the externality values for emitted criteria pollutants which would affect the costs of the proposed facility (id.). The Attorney General argued that EEC, therefore, was attempting to "have it both ways" (id.).

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83 Rulemaking Regarding the Procedures by Which Additional Resources are Planned, Solicited, and Procured by Investor-Owned Electric Companies (Integrated Resource Management), Final Order On Rulemaking, 21 DOMSC 91 (1990) ("Siting Council IRM Decision").

84 As will be explained in Section II.B.2.c, below, the Attorney General has incorrectly characterized the statements of the Siting Council in that decision.

85 The Department updated its environmental externality values in D.P.U. 91-131 (1992). As a part of that decision, the Department authorized the use of emissions offsets to reduce total emissions for which externality values must be applied. D.P.U. 91-131, at 92-114.

c. Analysis

As an initial matter, all parties agree that the Siting Board must review a proposed project in terms of its cost, environmental impacts, reliability and ability to address a demonstrated need. Implicit in such an analysis is that a need for the proposed project must first be established. As noted above, historically, the Siting Council addressed the need for a proposed project prior to any other analysis thereof. As the Court remanded the EEC Decision to the Siting Council "to compare alternative energy resources in its review of [EEC's] application" (413 Mass. at 484), the Siting Board will proceed with its comparison of alternatives in this case based on the assumption that the Siting Council's finding relative to need for the proposed project contained in the EEC Decision remains unchanged.[86]

The Siting Board acknowledges that the Court has clearly stated that, in a review of a petition to construct a power generating facility, the Siting Board's enabling legislation requires a review of alternatives to ensure that the statutory minimum impact standard has been met. The Court's support for the standard of review utilized by the Siting Council in its first three non-utility facility reviews provides the framework for the standard to be used herein.[87] However, the Siting Board does not interpret the Court's statement, in regard to

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[86] The Siting Board notes that the Court indicated that the finding of need for the proposed project was based on a finding of need for New England, and that this finding was inadequate. The Siting Board will address this issue in Sections II.C.2, II.C.3 and III.A, below. In addition, as updated need information was provided in the remand proceedings, the Siting Board will analyze the more recent need information in Sections II.C.4 and II.C.5, below.

[87] In implementing its statutory mandate in earlier facility reviews, including the three non-utility facility reviews, the Siting Council's standard of review required a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need and in terms of cost, environmental impact and reliability. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Council determined whether the project offers power at a cost below the purchasing utility's avoided cost. MASSPOWER Decision, 22 DOMSC at 337-352; Altresco Decision, 17 DOMSC at 370-378; NEA Decision, 16 DOMSC at 360-368; Cambridge Electric Light Company, 15 DOMSC 187, 212-218 (1986); Massachusetts Electric Company, 13 DOMSC 119, 141-183 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985).

the previous standard of review used by the Siting Council, to imply that there are no other standards of review which might also be appropriate. Thus, before the Siting Board conducts its analysis of alternative approaches we will first review the arguments of the parties regarding the standard of review.

In the first three non-utility facility reviews, the Siting Council compared the proposed projects with generic technology alternatives. The Attorney General here argues that an analysis of generic technologies is "per se" insufficient to comply with the statutory mandate to compare alternatives. We do not agree with this argument. To accept this argument, the Siting Board would have to ignore its statute and the statement of the Court that the comparison of alternatives that the Siting Council employed in its first three non-utility facility reviews "comports with the [Siting C]ouncil's statutory mandate." 413 Mass. at 485. In all three of those cases, the proposed project was compared to a set of generic alternatives.[88]

The Siting Board acknowledges that there may be instances when it may be appropriate to review non-generic alternatives, but the Court's approval in City of New Bedford of the comparison of generic alternatives that was used by the Siting Council in its first three non-utility facility cases indicates that there is no apparent statutory requirement to review non-generic alternatives, nor has any party cited to any such statutory requirement.[89] Further, in the EEC Decision, the Siting Council rejected arguments that "real" projects should be

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88 In EEC's original filing, the Company provided a comparison of alternatives consistent with past Siting Council practice. After the decision in City of New Bedford, EEC updated its information on alternatives. Information was also provided by intervenors on two additional alternative technologies which will be addressed below. Specifically, the Attorney General has proposed a coal-gasification process developed by Destec, Inc. as an alternative to the generic coal-gasification technology included in the comparison of alternatives provided by EEC. Further, NO-COAL proposed a methanol-powered technology.

89 The Siting Board acknowledges that it still has concerns with the comparisons of generic alternatives as explained in the MASSPOWER Decision; however, in light of the Court's directive, the Siting Board will attempt to address these concerns within our review.

compared to an applicant's proposed project due to serious constraints facing non-utility developers trying to obtain information on a large number of potential and planned projects and the fact that much of the specific information associated with such projects is confidential. 22 DOMSC at 283. In light of developments during the remand proceedings, such rejection continues to be warranted.[90]

In response to the Attorney General's argument that the Siting Board consider other projects that are currently being reviewed in separate dockets before the Siting Board as examples of other real alternatives, the Siting Board notes that the Attorney General has not identified a practical method for so doing, and there are several reasons that would make such a requirement problematic. First, most, if not all, dockets have documents that are protected from disclosure except to parties to that docket who have executed an appropriate confidentiality agreement. Thus, important information again would not be available to a project proponent were the Siting Board to rely on information from other dockets. Second, were the Siting Board to rely on information from other dockets on the basis that the Siting Board had special knowledge of the other information in those dockets, non-record information that would not be subject to cross-examination by applicants in the other dockets could inappropriately be used as a basis for a decision. Finally, to require a developer to provide an analysis of real project alternatives assuming that most developers are "sophisticated, experienced actors in the power generation field" would neither justify the additional costs associated with such an analysis, nor the time required to review such an

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90 In the remand proceedings, witnesses for both NO-COAL and the Attorney General refused to respond to various questions and requests for information relative to their specific alternative technologies explaining that the responses would require information they viewed to be proprietary or otherwise confidential (see, e.g., Tr. 25, at 51-56; Tr. JH2, at 12-22). Although these witnesses (1) agreed to provide some information only to the Siting Board, and (2) EEC and the Attorney General entered into an agreement to strike certain record information in response to a Motion to Compel, the Siting Board notes that full disclosure, subject to appropriate non-disclosure agreements, is necessary if the Siting Board is to be persuaded that specific, non-generic alternatives proposed by intervenors are superior to a proposed project.

analysis, both of which would make it more difficult for the Siting Board to provide necessary energy at the lowest possible cost.

As required by G.L. c. 164, § 69I(3), the description of alternatives to planned action is in response to the "actions planned which will affect capacity to meet [the electric power] needs or requirements [for the company's market area]." In previous decisions, technology alternatives were eliminated if they were generally not capable of providing for all of the identified need either as a result of capacity limitations, commercial unavailability, or amenability to only one site. MASSPOWER Decision, 20 DOMSC at 337-339; Altresco Decision, 17 DOMSC at 370-372; NEA Decision, 16 DOMSC at 368-373. In addition, a technology that is not a mature technology, i.e., a technology which is not yet commercially proven or is undergoing development on a commercial level, likely would not provide a reliable energy supply.[91] As such, the Siting Board requires the description of alternatives to include only those technologies which could meet the established need.[92,93]

With respect to the issue of C&LM, the Siting Board agrees with the Attorney General that a non-utility developer should not be excused from undertaking to study and describe the current and future reach of C&LM programs just because they may not be in a position to deliver C&LM. In fact, the Siting Board requires the non-utility applicant to include an analysis of the projection of capacity available from C&LM in its analysis of need (see Section II.C, below). This approach is consistent with the approach used by the Siting

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91 The maturity of the technology of the two alternatives proposed by the Attorney General and NO-COAL were questioned during the remand proceedings, the Siting Board will address this issue in Section II.B.5, below.

92 The Court acknowledged the appropriateness of this approach when it approved of the Siting Council's previous standard which required a non-utility applicant to establish that its proposed project was superior to alternative approaches in, among other things, its ability to address the previously identified need for energy. City of New Bedford, 413 Mass. at 485.

93 The Siting Board notes that if a proposed project operates on the principle of cogeneration, an alternative specifically mentioned in G.L. c. 164, § 69I, the comparison of alternatives to a proposed project should also consider their ability to provide steam as required by the proposed project's steam host.

Council in its prior facility reviews and the requirement of G.L. c. 164, § 69J that, among other things, the "projections of the demand for electric power ... include an adequate consideration of conservation and load management." The Siting Board notes that this approach in effect assumes a significant degree of C&LM contributions (including programs in the design stage) after which a need for additional capacity is determined. As a result, C&LM is not considered as an alternative to a proposed project, but rather is assumed to already be in place before any further need is identified."

The Attorney General argued that the requirement of G.L. c. 164, § 69I to provide a description of alternatives to planned action, among other things, must include "no additional electrical power or gas; [and] a reduction of requirements through load management."[94] However, the Attorney General ignores the fact that the "reduction of requirements through load management" is a separate clause from what is included in the statute as a description of

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[94] 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 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. The manufacturer receives some economic benefit for its willingness to shift its manufacturing to off-peak times. 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.

This distinction between "load management" and "conservation" is not ignored in the statute as evidenced by the language in Sections 69I and 69J. Projections of demand must include "an adequate consideration of conservation and load management." G.L. c. 164, § 69J (1992 ed.). Whereas, one of the enumerated actions included in the list of actions planned to be taken to meet future needs or requirements is "a reduction of requirements through load management." G.L. c. 164, § 69I (1992 ed.). The current version of the statute requires identical considerations in both Sections 69I and 69J. See G.L. c. 164, §§ 69I & 69J (1993 ed.).

alternatives. Alternatives to planned action as used in G.L. c. 164, § 69I includes such things as "other methods of generating, manufacturing or storing, other site locations, 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 no additional electrical power or gas." Load management is not included in this list. Therefore, the Siting Board finds that the analysis of load management as an alternative to the planned activity is not required by the statute.

The Siting Board notes that the specific requirement to include, in such form and detail as the Siting Board shall prescribe, a description of actions planned to be taken by a Company which will affect capacity to meet the identified need, including a reduction of requirements through load management, makes sense only in the context of a utility with specific knowledge of its customers and its unique mixture of supply options.[95] To require a non-utility developer to include a description of planned actions that states that it has no plans to take any action with regard to load management would be interpreting the statute in a manner contrary to common sense and sound judgment. See, Commissioner of Corp. & Tax v. Chilton Club, 318 Mass. 285, 288-289 (1945) and cases cited therein.[96] Thus, the Siting Board finds that a non-utility developer fulfills its statutory mandate with reference to a consideration of the reduction of requirements through load management when it complies with the requirement of G.L. c. 164, § 69J, which it does in the analysis of need.[97]

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95 The Siting Board notes that the Court has acknowledged that modifications may be necessary in the review of non-utility petitions to accommodate non-utility producers. City of New Bedford, 413 Mass. at 488. The Court stated that it would approve such modifications if they "permit a review that fulfills the statutory mandate." Id.

96 In fact, EEC maintains that it has no plans to take any action with regard to load management as it does not provide such services.

97 Analyzing C&LM as a part of the analysis of need is also reasonable for two reasons. First, if projected need can be met by C&LM, no analysis would be required of new generating projects as there would be no need for such a project. Second, the analysis of need provides a best estimate of expected future demand and the analysis of C&LM provides a best estimate of expected future savings from C&LM. As both are (continued...)

The Siting Board also finds that a description of the alternative of "no additional electric power or gas," when read in context of G.L. c. 164, §§ 69I and 69J, makes sense only in regard to a utility's long-range forecast or a utility's application to construct a facility. This requirement is to provide the regulator with a description of the consequences of a utility failing to act to meet its needs and requirements. In the context of a utility long-range forecast, the regulator would need to know the impacts of such a decision, e.g., would such non-action result in peak-day shortages, shortages only during unplanned outages of generating facilities, an increased reliance on interruptible customers, etc. In terms of a non-utility developer, this description of the alternative of no additional electrical power would require the non-utility developer merely to state that the need which has been identified would not be met. The non-utility developer would not be in a position to indicate which electric utilities would be impacted or what they might do in response to such a shortage as each utility must plan for shortages in a manner that responds to its unique situation.

Thus, the Siting Board acknowledges that it is necessary to modify the application of the statutory requirement for the review of non-utility developers with respect to the requirements of describing their actions relative to reducing requirements through load management and describing the alternative of no additional power. Such modification is necessary in order to construe the statute with common sense and sound judgment and comports with the Court's directive in City of New Bedford, as this modification, which is necessary to accommodate the non-utility developer, still allows for a review that fulfills the statutory mandate (413 Mass. at 488).

The Siting Board also rejects the Attorney General's argument that if C&LM is incapable of meeting the identified need, the Siting Board should consider a hierarchy of options commencing with renewable resources that are cleaner than fossil fuels. Establishing such a hierarchy would require the Siting Board to ignore the Court's directive that the Siting

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[97](...continued)
projections, it is reasonable to analyze them together rather than to compare a best estimate of expected C&LM to the specific known, not projected, MW output of an alternative technology.

Board's statutory mandate involves a balancing of minimum environmental impact and cost. Further, the hierarchy that is suggested by the Attorney General is based strictly on perceived, relative environmental impacts without reference to any record information to support his conclusions. Such an approach would eliminate the Siting Board's ability to determine whether proposed projects would be least-cost alternatives or to conduct a balancing of environmental impacts with cost as required by the statute. Thus, the Siting Board finds that the Attorney General's suggestion that the Siting Board establish a hierarchy of alternative resource options, commencing with renewable resources that are "cleaner" than fossil fuels would be inconsistent with statutory construction precepts that require each word of a statute to be given its appropriate effect without emphasizing one at the expense of others, as such a hierarchy is likely to elevate environmental impacts over other statutory considerations. See, Commissioner of Corp. & Tax, supra at 288-289.

Accordingly, the Siting Board finds that requiring a review of generic alternatives is an acceptable method at this time to ensure that the statutory minimum impact standard is met. The Siting Board, however, also finds that specific real projects that are supported by sufficient information to allow for a complete review by the Siting Board and all parties to the proceeding of its costs, environmental impacts, and reliability to meet an identified need, if presented by a party to the proceeding, may be used to compare with the proposed project. In addition, all parties to a proceeding may provide evidence to support findings that are contrary to the information provided by an applicant with regard to generic alternatives. Therefore, here, the Siting Board will review those generic alternatives proposed by the Company, including any evidence provided by intervenors that is contrary to the information provided by the Company with regard to generic alternatives, in addition to the two alternative technologies sponsored individually by the Attorney General and NO-COAL.

With regard to environmental externalities, the Attorney General argued that since the Siting Board must balance environmental impacts with cost, the environmental externality values in the Department's IRM regulations should be included in these costs. EEC noted that the Siting Council rejected such an argument in the EEC Decision, and further, that to incorporate the externality values in the cost analysis as well as comparing environmental impacts of alternatives would amount to double counting of the values.

As an initial matter, the Siting Board notes that, although the Department's environmental externality values are given in dollar figures, they do not, as the Attorney General argues, represent additional costs that would be added to a project's true internal costs of development and operation. Rather, they are assigned values for external factors, specifically for a select group of air emissions, which have been monetized to attempt to include the societal costs of those emissions for the purposes of a specific regulatory framework which includes numerous other cost and non-cost factors. The Siting Board further notes that the environmental externality values were developed after extensive rulemaking processes undertaken by the Department in 1990. In D.P.U. 89-239, these externality values were established and the stage of the IRM process to which they were to apply, i.e., resource acquisition, was defined.[98] The externality values were reaffirmed and adjusted to reflect inflation in D.P.U. 91-131. That decision, as it relates to the reaffirmation of the externality values, is currently under appeal to the Court.

The Department's externality values are used by the Department in an attempt to compare the air emission impacts of two or more resource alternatives that a utility is considering to meet its needs and requirements. Through the monetizing of air emissions, the Department is able to compare alternative projects on the basis of their respective costs and cumulative air impacts for those emissions that are monetized.[99] As noted above, costs and air emissions are not the only factors considered in an IRM review.

98 The Siting Board notes that the Attorney General was a party to this Department proceeding.

99 The Siting Board notes that externality values are identified only for the following air emissions: Carbon Dioxide; Carbon Monoxide; Methane; Nitrogen Oxides; Nitrous Oxide; Sulfur Oxides; Total Suspended Particulates; and Volatile Organic Compounds. No externality values have been identified for other air emissions or for other environmental impacts.

The Siting Board accepts the theoretical merit in an approach that would monetize external environmental impacts as a means of simplifying the comparison of environmental impacts and costs. The Siting Board notes, however, that the Department's externality values relate to only one area of environmental impact, i.e., air emissions, and even then, only to selected air emissions, whereas the statutory mandate of the Siting Board is to balance all environmental impacts to ensure that a minimum impact standard has been achieved. In fact, as noted above, the Attorney General has argued that "a full comparative review of the environmental consequences, relative benefits, and feasibility of using alternatives to any plant proposed by a developer" must be undertaken. The Siting Council's rejection in the EEC Decision of the incorporation of externality values in the facility siting process was due, in part, to the lack of comprehensiveness of the externality values. 22 DOMSC at 284. The Siting Council noted that the review of a non-utility developer's project takes into account concerns that are broader than simply what resources may be appropriate for a particular utility.[100] Id.

In fact, were the Siting Board to accept that the monetizing of all environmental impacts was required in order to balance them against cost, the appropriate course of action would be a generic rulemaking to develop such values.[101] Even with such a rulemaking,

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100 The Attorney General acknowledged that the externality values are underinclusive but argued that they should be applied and expanded as future externalities are monetized. The Siting Board notes that environmental externality values allow for a comparison of certain environmental air impacts. The Siting Board's comprehensive comparison of environmental impacts, which includes air impacts, is merely an alternate and more inclusive method of comparison. In addition, the Siting Board questions the appropriateness of relying on values, which are currently being appealed, to compare only one set of environmental impacts when alternative methods of comparison exist which would compare all environmental impacts in a uniform manner.

101 Alternatively, the Siting Board could approach such a monetization in each facility review. The Siting Board notes that not only would such an approach be an ineffective use of time and resources of all participants in the process, there is no reason for the Siting Board to believe that appropriate values could be achieved for all of the various environmental impacts that the Siting Council has historically considered. In addition, such an approach could lead to inconsistent results among different facility reviews.

however, the Siting Board notes that there is no guarantee that accurate values could be achieved. Thus, although there is potential merit in the monetization of all environmental impacts that the Siting Council has traditionally considered in its reviews, the Siting Board is not convinced that the effort that would be required to determine appropriate values for the various environmental impacts would result in a process that is an improvement over the comparison of environmental impacts which has been used by the Siting Council in its earlier decisions and accepted by the Court as achieving the statutory mandate of minimizing environmental impacts. Certainly the record in this proceeding does not support the establishment of any such values. Nor has any party to this proceeding presented sufficient information for the Siting Board to conclude that the use of the Department's values, which are currently under appeal, would be appropriate for application to a facility siting review, a context for which they were not promulgated,[102] as opposed to a utility specific resource acquisition process.[103]

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102 The Siting Board notes that the Attorney General has argued that since the Siting Board believes the IRM process is an efficient process for fulfilling its statutory mandate that adopting the Department's externality values in the siting process would be the most sensible approach for the Siting Board. The Siting Board continues to maintain that the IRM process is the appropriate framework for specific resource acquisition decisions. The Siting Board, however, does not find it appropriate to use regulations out of the context for which they were designed without sufficient evidence to establish that such a use is justified. No party in this proceeding has made such a showing relative to the Department's externality values.

103 Finally, the Attorney General's statement that the Siting Council's decision in the <u>Siting Council IRM Decision</u> supports the proposition that the consideration of externalities are not to be overridden by non-price criteria is incorrect. In fact, the Siting Council took precisely the opposite position. The Siting Council stated: "an electric company's diversity objectives conceivably could have a countervailing effect on that company's weighting of environmental externalities." 21 DOMSC at 141. Further, the Siting Council defined diversity much more broadly than "fuel diversity" as stated by the Attorney General. <u>Id.</u>, 21 DOMSC at n.22.

In addition, the Siting Council noted that the Department's approach to evaluating externalities was "part of a larger weighting scheme designed to recognize the value of (continued...)

Further, the purpose of the externality values, as noted above, is not to derive a dollar figure that indicates additional real costs of a project, but rather, is for the purpose of comparing two or more projects with different emissions. A comparison of alternatives can be accomplished without monetizing impacts. Such a non-monetized process was used by the Siting Council in the MASSPOWER Decision and earlier facility decisions, and, as noted above, was approved by the Court. The Siting Board undertakes this same type of comparison below. By proceeding in this fashion, the Siting Board is not ignoring a sister agency's regulations, nor is the Siting Board forever precluding consideration of the Department's externality values.[104] Rather, the Siting Board is employing a procedure for comparison of alternatives that does not require their use and that has been specifically recognized by the Court to comport with our statutory mandate.

Accordingly, the Siting Board finds that a comparison of alternatives can be undertaken that comports with our statutory mandate without including the Department's externality values for air emissions.[105] Further, the Siting Board finds that, based on the record in this proceeding, it would be inappropriate to apply the Department's environmental externality values in a review of EEC's proposed project.

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[103](...continued)
various attributes of resource options." Id. To consider externalities in such a manner as the Attorney General advocates would be tantamount to ignoring the basic premise upon which externalities was envisioned.

[104] The Siting Board notes, however, that a party seeking to have the Siting Board use values in a manner other than that for which they were designed would have to establish a basis for so doing. The Attorney General provided no such basis.

[105] The Attorney General also argued that G.L. c. 164 does not treat non-utility developers and utilities differently and, therefore, the Siting Board should not do so in the siting process by ignoring the use of environmental externality values in the review of a non-utility developer's project. The Siting Board notes, however, that neither utilities nor non-utility developers are required to apply environmental externality values in a siting review. Rather, both utilities and non-utility developers must address these values in the utility specific review of resource acquisitions.

Finally, the Siting Board notes that the Attorney General's argument that the use of emission offsets by the Company to reduce total emissions is contrary to the Company's position that environmental externality values should not be applied in the review of its proposed project is a misstatement of the relationship between the two issues. The use of environmental externality values is one approach to comparing alternatives, an approach that is duplicative of a comparison of environmental impacts of the proposed project and alternatives based on non-monetary measures. Emission offsets, in contrast, is a method by which new facilities can achieve more cost-effective reductions in impacts on the environment by reducing emissions from existing facilities, thereby achieving an energy supply that is lower in cost, has less impact on the environment, or some combination of the two. Emissions offsets are specifically approved under both state and federal regulatory schemes, including that in D.P.U. 91-131. The fact that EEC can achieve real benefits based on a state and federally approved offset program in no way detracts from the Siting Board's finding that a comparison of facilities can be accomplished without resorting to the monetization of impacts that results from the use of environmental externality values. Further, as emission offsets associated with a proposed project will result in real reductions in impacts as a result of those offsets and likewise will result in the incurring of real dollar costs, the Siting Board finds that, although not done in the present proceeding, it would be appropriate to include emission offsets and real dollar costs to be expended for those emission offsets in a comparison of alternatives.

d. Findings and Conclusions

In Section II.B.2.c, above, the Siting Board has made the following subsidiary findings:

- the analysis of load management as an alternative to the planned activity is not required by the statute (p. 56);
- a non-utility developer fulfills its statutory mandate with reference to a consideration of the reduction of requirements through load management when it complies with the requirement of G.L. c. 164, § 69J, which it does in the analysis of need (p. 56);

- a description of the alternative of "no additional electric power or gas," when read in context of G.L. c. 164, § 69I makes sense only in regard to a utility's long-range forecast (p. 57);
- the Attorney General's suggestion that the Siting Board establish a hierarchy of alternative resource options, commencing with renewable resources that are "cleaner" than fossil fuels would be inconsistent with statutory construction precepts that require each word of a statute to be given its appropriate effect without emphasizing one at the expense of others, as such a hierarchy is likely to elevate environmental impacts over other statutory considerations (p. 58);
- requiring a review of generic alternatives is an acceptable method at this time to ensure that the statutory minimum impact standard is met (p. 58);
- specific real projects that are supported by sufficient information to allow for a complete review by the Siting Board and all parties to the proceeding of its costs, environmental impacts, and reliability to meet an identified need, if presented by a party to the proceeding, may be used to compare with the proposed project (p. 58);
- a comparison of alternatives can be undertaken that comports with our statutory mandate without including the Department's values for air emissions (p. 62);
- based on the record in this proceeding, it would be inappropriate to apply the Department's environmental externality values in a review of EEC's proposed project (p. 62);
- although not done in the present proceeding, it would be appropriate to include emission offsets and real dollar costs to be expended for those emission offsets in a comparison of alternatives (p. 63).

The Siting Board has determined that the standard of review for the comparison of alternatives that was used by the Siting Council in its first three non-utility facility reviews, and which was based on standards used in earlier utility reviews, will be the standard of review used in this case and will be a basis for which the Siting Board reviews future cases. The Siting Board notes that this earlier standard has been acknowledged as appropriate by the General Court and, in City of New Bedford, the Court indicated that it complies with the

Siting Board's statutory mandate. Therefore, the Siting Board adopts the following standard of review, used in the MASSPOWER Decision.

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

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need and in terms of cost, environmental impact and reliability.[106] Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Board determines whether the project offers power at a cost below the purchasing utility's avoided cost. Altresco Decision, 17 DOMSC at 370-378; NEA Decision, 16 DOMSC at 360-380. See n.62, above and n.198, below.

3. Identification of Resource Alternatives

To address a need for at least 300 MW of additional energy resources by 1997,[107] EEC proposes to construct a 300 MW, CFB boiler cogeneration power plant in New Bedford (Exh. HO-1A at 1). EEC stated that the proposed project could be constructed in 36 to 39 months and that it is expected to commence commercial operation beginning in early 1997 (Exh. AG-RE-13).

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106 The Siting Board will include in its review site-specific impacts of both the proposed project and each alternative at the proposed site.

107 In the EEC Decision, the Siting Council found that New England needs at least 300 MW of additional energy resources for reliability purposes beginning in 1995 and beyond. 22 DOMSC at 241.

The Company examined several alternative approaches to address a need of at least 300 MW, including both non-conventional and conventional generating technologies, but considered only those alternative technologies that would constitute reasonable replacements in terms of size, construction time and compatibility with cogeneration (Exh. HO-AER-9(a)(A)). Therefore, the Company stated that it did not consider such non-conventional technologies as municipal solid waste, biomass, wind, solar-photovoltaic cells, and fuel cells because these are typically too small to satisfy the identified need of 300 MW (id.; Tr. 24, at 45-48). The Company noted that the largest of these technologies, municipal solid waste and biomass facilities, would generally be in the 20 MW to 65 MW range and that it would not be practical or cost-effective to construct a number of smaller facilities at the proposed site (Tr. 24, at 44-48). The Company stated that it also did not consider geothermal and hydroelectric technologies because these technologies would be incompatible with cogeneration (Exh. HO-AER-9(a)(A)).

EEC identified five technology alternatives that would constitute reasonable replacements for the proposed project as follows: (1) a pulverized coal steam plant ("PC"); (2) a natural gas-fired, combined cycle unit with firm, (i.e., 365 day), gas supply ("NGCC"); (3) a natural gas/oil-fired combined cycle unit with interruptible gas supply and a low-sulfur, distillate oil back-up ("GOCC");[108] (4) a residual oil-fired steam unit ("RO"); and (5) a coal-gasification combined cycle unit ("CGCC") (Exhs. HO-AER-9(a)(A); AG-RE-18, att. ii). As an alternative to the proposed project, the Attorney General identified a CGCC alternative which would utilize the Destec Energy, Inc. ("Destec") coal gasification process (Exh. AG-201).

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108 The Company assumed that an interruptible gas supply would be available for 10 months per year and that distillate oil would be fired for the remaining two months per year (Exh. HO-AER-9(a)(A)).

In addition, NO-COAL identified a methanol-fired combined cycle unit ("MCC") which would be supplied by a methanol plantship[109] as a viable alternative technology for electricity production for the mid- to late-1990's (Exh. NC-30; Tr. 25, at 41).[110]

EEC asserted that the MCC facility is not a practical alternative that is capable of meeting a need for 300 MW (EEC Brief at 90-91). EEC asserted that the MCC alternative does not have an identified source of supply, a plantship to produce the methanol, or any transportation or storage facilities (id.).

The record demonstrates that non-conventional technologies such as municipal solid waste, biomass, wind, solar-photovoltaic cells, and fuel cells are typically too small to satisfy a need of 300 MW and that it would not be cost-effective or practical to construct multiple facilities at the proposed site. The record also demonstrates that geothermal and hydroelectric technologies would be incompatible with cogeneration. Therefore, for the purposes of this review, the Siting Board finds that municipal solid waste, biomass, wind, solar-photovoltaic cells, fuel cells, geothermal and hydroelectric technologies are not reasonable alternative approaches to meeting a need of 300 MW and, therefore the Siting Board does not analyze these approaches.

With regard to an MCC facility, the Siting Board recognizes that this is not a proven technology at this point in time given that there is no existing fuel supply infrastructure and

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109 NO-COAL's witness, Mr. Calvert, explained that a plantship is a barge that contains equipment to convert offshore natural gas to methanol (Tr. 25, at 92).

110 NO-COAL explained that methanol would be produced aboard a plantship from a low-cost source of methane and transported to New Bedford harbor via a dedicated shuttle tanker (Exh. NC-30, at 1-3; Tr. 25, at 92, 115). NO-COAL stated that the methanol could be transported from New Bedford harbor to the proposed site via pipeline or rail and that storage facilities would be required at the harbor or on-site (Tr. 25, at 131-132, 146-152).

NO-COAL also explained that sources of low-cost feedstock would include: off-shore waste gas, such as methane that is currently flared in conjunction with oil production; gas fields that are not in production due to lack of infrastructure to enable use of the gas; and gas which would require disposal to allow production of oil from fields that are currently not utilized (Exh. NC-40, at A-8; Tr. 25, at 43, 51, 69).

there are no existing methanol-fired facilities with a fuel supply comparable to the fuel supply arrangement proposed by NO-COAL. However, the testimony of NO-COAL suggests that an MCC facility may have the potential to offer significant benefits with respect to environmental impacts and cost over traditional approaches. As such, in order to determine whether the potential environmental and cost advantages of the MCC technology could outweigh the disadvantage of its unproven status and provide a reasonable alternative to the proposed facility, the Siting Board will consider the MCC facility as a resource alternative in this review.

Therefore, for the purposes of this review, the Siting Board compares the environmental and cost impacts of the proposed CFB project to the NGCC, GOCC, CGCC, RO, PC and MCC alternatives at the proposed site.

4. Environmental Impacts

EEC asserted that its proposed project was comparable from an overall environmental impact perspective to the NGCC, GOCC, PC and RO alternatives but superior to the CGCC alternative (EEC Brief at 114).[111] The Company based this assertion on an analysis of environmental impacts including fuel transportation, air quality, water supply and wastewater, noise, solid waste, and land use (Exh. AG-RE-18, att. iii.). The Company stated that potential impacts associated with each of the technologies at the proposed site were determined based on a net generating capability of 300 MW, 85 percent annual plant availability, and an assumed export of 207,000 lbs/hr of high pressure cogeneration steam (id., att. iii at 1-2).

a. Fuel Transportation

i. Description

The Company indicated that fuel for the proposed project or technology alternatives could be transported to the property site by rail or pipeline (id., att. i, Table 6.1). EEC asserted that rail transportation would be preferable because the site is served by an active

111 The Company did not include an MCC facility in its environmental analysis of technology alternatives. See Section II.B.3., above.

Conrail line while pipeline transportation would require the construction of facilities which would have substantial environmental impacts (EEC Brief at 116-121). Thus, the Company asserted that the proposed project, and the PC, RO and CGCC alternatives, which would rely on rail transportation, would be preferable to the NGCC and GOCC alternatives which would rely primarily on pipeline transportation (id.).

With regard to the proposed project, the Company indicated that five round-trip unit trains -- four coal trains[112] and one limestone train -- would be required weekly (Exh. HO-RR-106, rev.). To deliver coal and limestone to the active site area, EEC stated that a new section of railroad track would be installed parallel to the existing Conrail line to the east of the proposed project site, and that a new rail spur would connect the new parallel track to a ladder-type train breakdown yard and the unloading area (Exhs. HO-1A at 24-25; HO-65E, rev. G). To minimize potential impacts to wetlands located between the existing rail line and active facility site, the Company indicated that the design and alignment of the rail spur and train breakdown yard would avoid wetlands and environmental resources to the greatest extent possible (Exh. HO-65E, rev. G; Tr. 22, at 35).

The Company indicated that the coal and limestone would be transported by way of Framingham, Massachusetts (Exh. HO-RR-106). From Framingham to the proposed site, rail transportation would continue via four existing rail segments (id.).[113] EEC indicated that although rail traffic on these segments would increase, such increased traffic would remain within the freight capacity and class of each of the rail segments (id.).[114] The Company noted that previous use of the rail route from Framingham to the site was

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112 The Company indicated that 8,600 coal cars per year would be required (Exh. AG-RE-18, att. i,Table 6.1).

113 EEC indicated that the four rail segments between Framingham and the site would be the Framingham Secondary, the Amtrak Main, Middleboro Secondary and New Bedford Secondary (Exh. HO-RR-106).

114 EEC indicated that weekly rail traffic would increase from 162 to 172 trains, or six percent, on the Amtrak main, from 12 to 22 trains, or 83 percent, on the Framingham Secondary and from four to 14 trains, or 350 percent, on the Middleboro and New Bedford Secondarys (Exh. HO-RR-106).

significantly greater than current levels of use and that the increase in rail traffic due to the operation of the proposed project would be insignificant compared to historical use (id.). The Company stated that the coal and limestone trains would cross 68 at-grade road crossings along the route from Framingham to the proposed site (id.). EEC studied the impact of the trains on the three at-grade road crossings in the immediate vicinity of the proposed site and concluded that traffic flow would not be disrupted (Exh. HO-2A at 5-65, 5-89, 5-90). The Company explained that the rail spur leading from the New Bedford Secondary to the facility site would be designed to minimize any delays at the road crossing leading directly into the GNB Industrial Park and that train deliveries to the proposed project would be scheduled during the daytime but not during morning and afternoon peak commuter hours (id. at 5-65; Exh. HO-E-114; Tr. 17, at 28).

With regard to the NGCC alternative, EEC stated that construction of natural gas pipeline facilities would be required in order to transport natural gas on a firm basis to the site (Exh. HO-RR-105). EEC provided a preliminary analysis, prepared by the Algonquin Gas Transmission Company ("AGT"), indicating that such facilities would include: (1) a dedicated 16-inch diameter pipeline from an existing AGT lateral pipeline to the facility site; (2) an on-site meter station; and (3) potential expansion of mainline facilities including likely installation of approximately 13 miles of pipeline loop and additional compression (id.; Exh. AG-RE-39, supp.).[115]

With regard to the dedicated pipeline, EEC stated that AGT suggested three preliminary routes, varying from 3.0 to 3.8 miles in length (Exh. HO-RR-105).[116] The Company stated that a 50-foot to 70-foot wide ROW would be required for each of the

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115 The Siting Board notes that pipeline looping refers to the installation of a new pipeline adjacent to existing pipeline. AGT indicated that detailed studies would be required to determine the exact nature and location of mainline facility upgrades that would be required (Exh. AG-RE-39, supp.).

116 The Company indicated that the three routes identified by AGT would begin at two alternative tap points on AGT laterals in the vicinity of the site, and that one route would require a virgin right-of-way ("ROW") while two of the routes would essentially follow existing electric ROWs (Exh. HO-RR-105).

routes, each would cross environmentally sensitive resources such as streams, wetlands and cranberry bogs, and that environmental impacts of pipeline construction would include vegetative clearing and alteration, permanent tree clearing, potential blasting, soil disturbance, and increased stream turbidity (id., Exh. AG-RE-18, att. iii at 4-6).

With regard to the GOCC alternative, the Company stated that both pipeline and rail transportation of fuel would be required (id., att. i, Table 6.1).[117] EEC stated that transportation of natural gas to the site on an interruptible basis would require a dedicated pipeline and meter station comparable to the NGCC facilities, but that expansion of mainline facilities would not be required (Exh. HO-RR-105, sup.). EEC stated that, additionally, the GOCC alternative would require up to 1,200 tank cars per year to transport oil (Exh. AG-RE-18, att. i, Table 6.1).[118,119]

With regard to the CGCC alternative, the Company indicated the existing rail also could be used to transport coal to the site (id., att. iii, at 2-3). EEC stated that although 9,200 rail cars would be required annually for coal supply, overall rail traffic to the CGCC alternative would be less than rail traffic to the proposed project because no limestone would be required for the CGCC alternative (id., att. i, Table 6.1; Exh. HO-AER-41). However, the Company noted that potential disadvantages to the CGCC alternative would be (1)

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117 The Company asserted that the primary fuel transportation impacts for a GOCC would relate to construction of a natural gas pipeline (EEC Brief at 117).

118 The Company based its estimation of the number of tank cars on a predicted use of oil for two months (Exh. AG-RE-18, att. i, Table 6.1).

119 The Company indicated that the GOCC alternative also could utilize trucks to transport oil to the site (Exh. AG-RE-18, att. iii at 3). However, the Company stated that the existing rail system is better equipped to handle the volume of fuel that would be required (Exh. HO-AER-38). In addition, the Company stated that truck deliveries potentially would have greater environmental impacts than rail delivery because truck deliveries would be more frequent and present increased opportunities for spillage (Tr. 22, at 134-135).

additional transportation of back-up fuel,[120] and (2) greater rail construction impacts to on-site wetlands (id.; Tr. 22, at 35-36, 133-134).[121]

Finally, EEC indicated that the PC and RO alternatives could utilize the existing rail system to transport coal or oil to the site (Exh. AG-RE-18, att. iii at 2-3). The Company estimated that the PC alternative would require 9,100 rail coal cars per year and that the RO facility would require 8,000 tank cars per year (id., att. 1, Table 6.1).[122] The Company stated that coal and limestone delivery for the PC alternative would have essentially the same impact on the rail system as rail delivery for the proposed project (Exh. HO-AER-41). In comparing rail transportation of oil and coal, the Company stated that, in the event of a spillage, oil, which could migrate into soil and groundwater, would cause greater environmental damage than coal, which is inert and easily remediated (Tr. 22, at 135)

The Attorney General argued that there would be environmental impacts associated with both the construction of the rail spur and pipeline (Attorney General Brief at 150-151). The Attorney General noted that rail spur construction would extend across wetlands and a stream to the north of the proposed project (Exh. HO-E-83). The Attorney General further noted that two of the three pipeline routes suggested by AGT would follow existing ROW, thereby minimizing potential environmental and construction impacts (Exh. AG-RE-39, sup., att.).

With regard to the MCC alternative, NO-COAL stated that methanol would be transported from the plantship to New Bedford harbor by two dedicated shuttle tankers and

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120 EEC stated that the assumed availability factor for the CGCC alternative would likely require alternative fuel back-up (Tr. 24, at 94, 114). See Section II.B.4.a.ii., below.

121 EEC stated that construction of rail facilities for the CGCC alternative would potentially have a greater impact to on-site wetlands impacts if the configuration of facility components could not be located as optimally as the proposed project (Tr. 22, at 35-36).

122 EEC indicated that fuel also could be delivered to the RO alternative by truck rather than rail but that truck transportation would potentially result in greater environmental impacts due to the additional frequency of delivery and increased opportunities for spillage (Exh. AG-RE-18, att. iii at 3).

then would be transported the ten-mile distance from the New Bedford Harbor to the site by rail or pipeline (Exh. EEC-RR-16; Tr. 25, at 149-151). NO-COAL stated that off-loading facilities and the shuttle tankers would be designed specifically to accommodate any existing limitations of New Bedford harbor (Exh. EEC-RR-16; Tr. 25, at 140-141). In discussing the impact of potential methanol spills on biotic life, NO-COAL's witness, Mr. Fink, indicated that methanol would be diluted by any water into which it is spilled, and although it could have an impact on marine biota, other substances stored on the plantship and shuttle tanker, such as fuels, lubricants and solvents, would have greater adverse impacts on marine biota (Exh. EEC-RR-14; Tr. 25, at 122).

With regard to transporting methanol to the site by railroad, NO-COAL's witness, Mr. Ladino, estimated that fifty, 20,000-gallon railcars would be required daily (Tr. 25, at 150). He stated that an inactive railroad line currently extends from the harbor area to the site, and that these tracks could be expanded to a methanol transportation depot and refurbished in order to transport methanol to the site (id. at 150-154). He noted that land use along the potential rail route is primarily industrial (Tr. 26, at 81).

However, Mr. Ladino stated that pipeline transportation would be preferable to rail transportation in that a pipeline would not be subject to weather delays, strikes, potential above-ground interruptions or future permits (id. at 150-151). He stated that, although no investigation had been made into potential pipeline routes, one possible route would be along the existing railroad corridor (id. at 165).[123] NO-COAL's witness, Mr. Booras, added that there are a number of unused pipelines in the area that could potentially be used to transport methanol but that a specific pipeline had not been identified (id. at 164-165).

ii. Analysis

With regard to rail transport of coal and limestone to the proposed project, the record demonstrates that the proposed site is served by an active Conrail line and that five round-trip unit trains would be required weekly. The record further demonstrates that, from

[123] NO-COAL stated that the feasibility of locating a methanol pipeline in proximity to a railroad and across wetlands had not been investigated (Tr. 25, at 164-165).

Framingham to New Bedford, the rail route would follow four rail segments and would traverse 68 grade crossings. These route segments have previously experienced greater frequency of use than current levels of use, but the addition of ten unit trains per week along this route would represent a substantial increase from current levels in rail traffic along two segments of the route. Although the Company has considered potential traffic impacts in the vicinity of the site, there would be potential traffic flow delays at a significant number of at-grade crossings from Framingham to the site. In addition, rail transport of fuel would require construction of a spur from the existing tracks to the facility site which would potentially impact wetlands. However, the Company would minimize impacts by the design and alignment of the spur.

In comparing rail requirements of the CGCC alternative to the proposed project, the record demonstrates that the CGCC alternative could require slightly more coal cars than the proposed project on an annual basis.[124] However, the CGCC alternative would require one less weekly unit delivery train than would be required by the proposed project because limestone would not be required, and thus, the overall rail traffic would be less for the CGCC alternative. With regard to potential wetlands impacts associated with the construction of the rail spur, the land requirement of the CGCC alternative would be comparable to the land requirements of the proposed project (see Section II.B.4.f., below). Therefore, wetlands impacts of the rail spur construction would likely be comparable for the CGCC alternative and the proposed project.[125] Accordingly, based on the foregoing, the

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124 Based on the heat rate calculated by the Company for the CGCC alternative, the CGCC alternative would require approximately seven percent more coal cars on an annual basis. However, the Siting Board notes that coal requirements of the CGCC facility would decrease with a reduction in the facility heat rate. See Sections II.B.4.b. and II.B.5., below.

125 The Siting Board notes EEC's argument that facility layout of the CGCC alternative might not be as optimal as the proposed project. However, without further information, there is insufficient evidence to support EEC's claim of greater impacts to on-site wetlands.

Siting Board finds that the CGCC alternative would be minimally preferable to the proposed project with respect to transportation impacts.

With regard to the PC alternative, the record demonstrates that coal and limestone requirements would be similar to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the PC alternative would be comparable to the proposed project with respect to transportation impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that overall rail traffic would be less for the RO alternative. However, the record also demonstrates that, in the event of accidental spillage, the environmental impacts of oil, which would migrate into soil and groundwater, would be significantly greater than the impacts of either coal or natural gas accidentally released into the environment. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to transportation impacts.

With regard to pipeline delivery of firm natural gas supplies to the NGCC alternative, the record demonstrates that construction of pipeline facilities would be required, including (1) a three- to four-mile dedicated pipeline from existing AGT facilities, and (2) an on-site meter station. In addition, construction along AGT mainline facilities would be required, including possible construction of 13 miles of pipeline and additional compression. The record further demonstrates that construction of the dedicated pipeline would potentially impact environmentally sensitive resources such as wetlands, streams, and cranberry bogs and that permanent impacts to resources could include vegetative alteration and tree clearing. However, the severity of the impacts would vary according to the chosen route and extent of facilities that would be required. The Siting Board notes that specialized construction techniques as well as route selection and adjustments in pipeline alignment could minimize disturbance. Further, two of the suggested routes would follow existing ROWs, thereby eliminating the need for construction of virgin ROW through potentially sensitive areas.

Thus, pipeline transportation could have significant construction-related impacts as well as permanent impacts such as vegetative alteration and tree clearing, depending on the route chosen and the vegetation and terrain along the route. Rail transportation, on the other hand, would not have construction-related impacts, but would have continual impacts over the life of the project, with respect to locomotive noise and potential traffic interruptions along the route. The Siting Board recognizes that such impacts could be mitigated to a certain extent with input from the communities along the route.

Although the record identifies generally the potential construction-related and permanent impacts of pipeline transportation, the record also indicates that these impacts would vary greatly according to the chosen route. Due to this variation, the potential impacts of fuel transportation of the NGCC alternative would be signicantly less or significantly greater than the impacts of the proposed project. Therefore, absent route specific information, the record does not allow for an accurate comparison of the likely transportation impacts of the proposed project with the potential but unknown transportation impacts of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board can make no finding regarding the relative transportation impacts of the proposed project and the NGCC alternative.

With regard to the GOCC alternative, the record demonstrates that the primary transportation impacts would relate to construction of pipeline facilities necessary to transport interruptible supplies to the proposed site -- a three- to four-mile dedicated pipeline and on-site meter station. As in the case of the NGCC alternative, the potential transportation impacts of use of a virgin pipeline ROW could be significantly greater than the transportation impacts of the proposed project. However, even if the pipeline route followed an existing ROW and impacts were reduced accordingly, due to the oil requirements for the GOCC alternative for a maximum of two months, the environmental impacts of accidental oil spillage also must be considered. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to transportation impacts, irrespective of pipeline route differences.

Finally, with regard to methanol, the record demonstrates that a combination of ocean tanker and land-based transportation would be required to deliver methanol to the proposed site. Methanol would be transported a significant distance from the methanol plantship to new off-loading facilities in New Bedford harbor by dedicated tanker shuttles. In the event of accidental spills of methanol or other substances at sea or in New Bedford harbor, adverse impacts to marine biota likely would occur.

Once unloaded, rail or pipeline would be options to transport the methanol from the harbor to the site. Pipeline transportation would require construction of a ten-mile long pipeline or use of an existing, abandoned pipeline, if available. However, proposed routes, other methanol pipeline requirements, and the existence or feasibility of use of abandoned pipelines have not been investigated.

With respect to rail transport of methanol, an abandoned rail line extends from the site to the harbor vicinity. However, the feasibility of utilizing this line to transport methanol has not been investigated. Rail transportation of methanol would require construction of a rail extension from the existing line to the methanol off-loading facilities in the harbor and potential construction along the existing line. In addition, the impact of the substantial number of rail cars that would be required on a daily basis along the route has not been investigated.

Thus, methanol transportation would result in environmental impacts related to both ocean tanker transport and land-based transport. While the record is insufficient to identify the full extent of potential impacts associated with methanol transportation, a basic comparison to the rail transportation for the proposed project can be made. Specifically, although the rail route from the New Bedford harbor would clearly be significantly shorter than the rail route to transport coal to the site, a substantially greater number of methanol rail cars would be required to supply the facility. Further, impacts to the harbor and marine biota would be incurred. Thus, although not fully investigated, the record demonstrates that the potential fuel transportation impacts of the MCC alternative would be greater than those of the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the MCC alternative with respect to transportation impacts.

b. Air Quality

The Company asserted that the overall air quality impacts of the proposed project would be comparable to those of the NGCC, GOCC, RO and PC alternatives, and that the air quality impacts of the CGCC alternative would be more significant than those of all other technologies (EEC Brief at 125-126).

In comparing the air quality impacts of the proposed project and technology alternatives, EEC considered: (1) estimated emission rates of criteria pollutants including sulfur dioxide ("SO_2"), nitrogen oxides ("NOx"), carbon monoxide ("CO"), particulate matter ("PM-10"), and volatile organic compounds ("VOC"); (2) emission rates of carbon dioxide ("CO_2"); (3) the predicted ambient levels of criteria pollutants in relation to the National Ambient Air Quality Standards ("NAAQS");[126] and (4) the net effect of the dispatch of the proposed project and the GOCC alternative on regional emissions of pollutants (Exh. AG-RE-18, att. iii, at 11-18). In comparing the air quality impacts of the proposed project and the CGCC alternative, the Company also considered the air quality impacts of benzene and hydrogen sulfide ("H_2S") emissions (Exhs. AG-RR-50; AG-RR-51).

In this section, the Siting Board first reviews the comparative emission rates of the proposed project and technology alternatives and the impact of such emissions on ambient air quality. The Siting Board then reviews the potential net effect of the dispatch of the proposed project and GOCC alternative on regional emissions.

i. Emission Rates and Impact on Ambient Air Quality

(A) Description

(1) Emission Rates

In estimating the emission rates, in tons per year ("tpy") of criteria pollutants and CO_2, for the proposed project and the NGCC, GOCC, CGCC, RO and PC technology alternatives, the Company assumed: (1) generation of 300 MW of electricity at 85 percent plant availability; (2) a technology-specific heat rate in British thermal units ("Btu") per kilowatt

126 EEC stated that NAAQS are ambient ceilings for specific pollutants, i.e., criteria pollutants, based upon the identifiable effects the pollutants may have on public health and welfare (Exh. HO-2B at F.1-2).

hour ("Btu/kWh");[127] and (3) emission factors, in pounds per million Btu ("lb/MMBtu"), consistent with fuel characteristics and specific control technologies (Exh. AG-RE-18, att. ii).[128]

With regard to the proposed project, the Company indicated that the heat rate of 10,200 Btu/kWh was based on the design of the facility and that emission rates of criteria pollutants were based on the control technologies[129] and emission factors contained it its draft air permit (Exh. AG-RE-18, att. ii; Tr. 24, at 136).[130] See Table 1.

With regard to the technology alternatives -- NGCC, GOCC, CGCC, RO and PC -- EEC indicated that heat rates were based on the heat rates set forth in the Electric Power Research Institute ("EPRI") Technical Assessment Guide dated September 1989 ("1989

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[127] The Company indicated that facility heat rate refers to the efficiency of conversion of thermal energy to electrical energy and that a lower heat rate refers to greater efficiency, decreased fuel requirements and emissions (Tr. 24, at 133; Tr. 22, at 27-29). The Company's witness, Mr. La Capra, estimated that a decrease in facility heat rate of 1,000 Btu/kWh would increase fuel efficiency approximately ten percent (Tr. 23, at 124).

[128] The Company based CO_2 calculations on the fuel-firing rate and fuel-carbon content and assumed all carbon in fuel would be converted to CO_2 (Exh. AG-RE-38b).

[129] EEC indicated that the proposed project would include the following emission control technologies: (1) limestone injection to minimize SO_2 emissions; (2) ammonia injection [selective non-catalytic reduction ("SNCR")] to minimize NOx emissions; (3) combustion optimization to minimize VOC and CO emissions; and (4) a fabric filter to minimize PM-10 and lead emissions (Exhs. HO-2A at 5-21, 5-23, 5-24; HO-65A at 6).

[130] In calculating SO_2 emissions for the proposed project, EEC assumed use of 2.4 percent sulfur coal (Tr. 22, at 24). EEC indicated that the emission limitation of 0.23 lb/MMBtu contained in the draft conditional approval of its air permit application would be achieved with this coal (id.; Exh. AG-RE-14).

In the EEC Compliance Decision, the Siting Council found that SO_2 emissions should be limited to 0.225 lb/MMBtu or could increase to 0.25 lb/MMBtu with a reduction of SO_2 emissions from other generating facilities in Massachusetts (25 DOMSC at 346-347).

TAG"),[131] adjusted for (1) additional NOx controls that would be required consistent with recent Massachusetts Department of Environmental Protection ("MDEP") determinations of Best Available Control Technology ("BACT"),[132] and (2) the addition of air-cooled condensers and steam export, consistent with the cooling technology and cogeneration application of the proposed project (Exh. HO-AER-9(a)(A), sec. 5.2).[133]

With respect to the NGCC alternative, EEC indicated that it assumed a heat rate of 9,426 Btu/kWh (Exh. AG-RE-18, att. i, Table 6.3). EEC estimated the emission factor for NOx based on the data for a proposed NGCC facility and estimated the emission factors for the remaining criteria pollutants based on 1991 permitted rates for an operational NGCC facility (id., att. ii; Tr. 22, pp. 109-110).[134] See Table 1.

The Attorney General argued that the Company's own calculations demonstrate that the pollutant emissions of a NGCC facility would be measurably less than those of the proposed project (Attorney General Brief, pp. 137-138). The Attorney General further argued that the

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131 EEC indicated that the following air pollution controls were included in the 1989 TAG for the technology alternatives: (1) water injection for NOx control for the NGCC and GOCC alternatives; (2) fabric filter and limestone flue gas desulfurization for the PC alternative; (3) electrostatic precipitator for PM-10 control for the RO alternative; and (4) a particulate removal unit, acid gas removal system and sulfur recovery plant for the CGCC alternative (Exh. HO-AER-18).

132 EEC indicated that additional NOx controls, based on current BACT determinations, would include selective catalytic reduction ("SCR") technology for the NGCC, GOCC and CGCC alternatives, and SNCR for the PC and RO alternatives (Exh. HO-AER-9(a)(A), sec. 5.2).

133 EEC indicated that the heat rates for all technology alternatives were increased by 2 percent to account for utilization of air-cooled condensers and increased by 965 Btu/kWh to reflect the export of 207,000 pounds of steam per hour (Exh. HO-AER-9(a)(A), sec. 5.2).

134 In order to account for Clean Air Act amendments that will require reduced NOx emissions, the Company stated that it based its estimate of a NOx emission factor on the estimated rate for a proposed facility that was lower than the permitted rate of any operational facility (Tr. 22, at 110). The Company indicated that it assumed SCR with steam injection for NOx control (Exh. AG-RE-18, att. ii).

Company overstated the NGCC heat rate, and thus, the emissions advantage of the NGCC alternative would be even greater (id.). The Attorney General stated that the heat rate for a currently proposed NGCC facility, with adjustments for comparability to the proposed project, would be 7,858 Btu/kWh, 17 percent lower than the heat rate of 9,426 Btu/kWh assumed by EEC (id. at 139; Exh. HO-RR-110). The Attorney General argued that, given that BACT determinations are driven by technological advances over time, it would be appropriate for the Company to base its comparison on the lower heat rate (Attorney General Brief at 139-140, citing, Tr. 23, at 113).[135]

EEC responded that its calculation of the heat rate for the NGCC alternative was based on an EPRI report, adjusted for use of air-cooled condensers, cogeneration and NOx control technology (EEC Reply Brief at 61).

With respect to the GOCC alternative, the Company indicated that the heat rate would be 9,426 Btu/kWh when firing gas and 9,246 Btu/kWh when firing oil (Exh. AG-RE-18, att. i, Table 6.1). EEC estimated emission factors assuming distillate oil firing, based on engineering calculations and data from other facilities (id., Table 6.3).[136] See Table 1.

For the CGCC alternative, EEC calculated the heat rate to be 10,830 Btu/kWh (Exh. AG-RE-18, att. ii). EEC stated that emission factors, in lb/MMBtu, were based on (1) control technology efficiencies for NOx and SO_2,[137] and (2) permitted and projected

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135 In addition, the Attorney General argued that EEC erred in calculating VOC emissions for the NGCC and GOCC alternatives (Attorney General Brief at 140-142). The Attorney General compared the Company's estimated VOC emissions to the Company's initially estimated VOC emissions in its original petition for these alternatives (id.). The Attorney General stated that EEC's estimated VOC emissions increased from the original petition but should have decreased due to lowered heat rate and decreased oil usage assumptions (id.).

The Company responded that its most recent analysis is based on BACT levels for an existing facility and therefore is sound (EEC Reply Brief at 61).

136 EEC assumed SCR with steam injection for NOx control (Exh. AG-RE-18, att. i).

137 The Company estimated NOx emissions based on controlling NOx to 9 parts per (continued...)

emission factors for two proposed CGCC facilities for the remaining pollutants (id.).[138,139]

The Attorney General argued that EEC erred in calculating CGCC emissions by overstating the facility heat rate and emission factors and that the CGCC alternative would produce significantly less air emissions than the proposed project (Attorney General Brief at 168-175).[140]

Dr. Breton provided alternative heat rate and emission factor calculations for the CGCC alternative, based on the Destec gasification process (Exhs. AG-201 at 10; AG-205).[141] Dr. Breton initially calculated that the heat rate for a Destec CGCC facility,

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137(...continued) million ("ppm") by steam injection and SCR (Exh. AG-RE-18, att. ii). Although the Company assumed that SCR would be technically possible, the Company stated that there are no existing CGCC facilities that incorporate SCR and that the NOx emission rate for an existing facility is greater than 9 ppm (Tr. 22, at 111). EEC estimated SO_2 emissions assuming the sulfur removal process would be 95 percent efficient, consistent with 1989 TAG data (id.).

138 The Company noted that its estimates included only those emissions related to the combined cycle portion of the process and emitted from the heat recovery steam generator ("HRSG") stack, and did not include emissions from the gasification process stacks, which would be emitted from the tail gas incinerator and flare stacks (Tr. 22, at 22). EEC stated that SO_2 emissions from the flare stack would increase overall facility emissions by approximately two percent but would not affect facility compliance with short-term SO_2 NAAQS (id. at 163-169; Exh. AG-RR-48).

139 The Company also estimated emissions of benzene and H_2S for the CGCC alternative. See Section II.B.4.b.i.(A)(2)(b), below.

140 In response to a record request of the Attorney General, the Company estimated the emissions of the CGCC alternative based on the lower heat rate assumed by the Attorney General (Exh. AG-RR-45). See Table 2.

141 Dr. Breton stated that Louisiana Gasification Technology, Inc. ("LGTI"), is a 160 MW power generating facility that is a demonstration facility for the Destec gasification process (Exh. AG-201, at 3-4). Dr. Breton added that the Wabash River Coal Gasification Repowering Project ("Wabash") is an integrated coal gasification combined-cycle repowering project, funded in part by the United States Department of (continued...)

comparable to the proposed project, would be 9,872 Btu/kWh[142] and indicated that emission factors would be lower than the emission factors estimated by the Company (Exhs. AG-201 at 10, 12-15, att. D; EEC-AG-112; AG-RE-18, att. i, Table 6.3).[143] See Table 2.

During the course of the proceeding, Dr. Breton recalculated the heat rate to be 8,814 Btu/Kwh (Exh. AG-205, rev.).[144] Dr. Breton noted that such a decrease in heat rate would further decrease annual fuel requirements and pollutant emissions in tpy (Tr. 30, at 12-14). However, Dr. Breton noted that there are no existing 300-MW CGCC facilities with the characteristics described in his process simulation model (id. at 31-32).[145] Dr. Breton also noted that the expected heat rate of the Wabash facility was higher than the estimated heat rate based on his own calculations because the heat rate of the Wabash facility reflects a repowered steam turbine rather than a new steam turbine (Tr. JH9, at 7-8).

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[141](...continued)
Energy, that uses the Destec gasification process and is scheduled to begin commercial operation in 1995 (id. at 7-8).

[142] Dr. Breton indicated that the initial heat rate he calculated was based on a 1992 EPRI study of a hypothetical 510 MW CGCC facility, adjusted to account for the size, cooling technology and steam export of the proposed project (Exhs. AG-201, at 10; EEC-AG-92; Tr. JH-9 at 4). Dr. Breton also indicated that coal requirements, based on his heat rate, would be 835,000 tpy, a reduction over the 916,000 tpy assumed by the Company (Exh. AG-210, at 10).

[143] Dr. Breton stated that his emission factors were based on expected emissions rather than permitted emissions for Wabash and emissions for similar processes in other industries (Tr. JH3, at 9-10, 12-13).

[144] Dr. Breton indicated that he derived the heat rate of 8,814 Btu/kWh based on a process simulation, which calculated the mass and energy balance for a 300 MW CGCC facility comparable to the proposed project (Exh. AG-205; Tr. 30, at 5-6). Dr. Breton explained that the heat rate differed from the originally calculated heat rate which was based on the EPRI study due to differing assumptions, including steam pressure, coal characteristics, and NOx control (Tr. 30, at 43-44).

[145] Dr. Breton indicated that a vendor guarantee for heat rate likely would be based on the performance of an existing facility, including a margin of error (Tr. 30, at 31-32).

With regard to heat rate calculations, EEC responded that heat rate for a CGCC facility would not be lower than the heat rate for the proposed project and that Dr. Breton's heat rate calculations were theoretical and unrealistic (EEC Brief at 140).[146] In addition, EEC asserted that Dr. Breton's heat rate calculation: (1) was not based on a specific turbine; (2) assumed a higher pressure than EEC would expect to apply; and (3) failed to account for specific environmental mitigation that would increase heat rate (EEC Brief, n.17, citing, Tr. 30, at 29-42).

Further, EEC asserted that the Siting Board should be skeptical of Dr. Breton's computer simulation model in light of the variety of heat rates it has produced (id. at 68). EEC added that the Attorney General's focus on heat rate calculations fails to address the air quality impacts of the CGCC alternative (id.). However, EEC acknowledged that, with respect to criteria pollutants, the record demonstrates that the CGCC alternative with a lower heat rate would have an insignificant impact on ambient air quality, an impact that would be comparable to the proposed project (id.). See Section II.B.4.b.i.(A)(2), below.

With respect to the RO alternative, the Company estimated the heat rate as 10,858 Btu/kWh (Exh. AG-RE-18, att. i, Table 6.1). EEC estimated emission factors based on recent BACT determinations and engineering calculations (id., att. ii). See Table 1.

With respect to the PC alternative, the Company estimated the heat rate as 10,701 Btu/kWh (id., att. i, Table 6.1). EEC estimated emission factors based on engineering calculations, recent BACT determinations and emission limits for the proposed project (id., att. ii). See Table 1.

In sum, in comparing the annual emissions of the proposed project and the technology alternatives, the Company indicated that the NGCC alternative would have the lowest emissions with respect to NOx, SO_2, PM-10, and CO_2, that the RO would have the lowest emissions with respect to CO, and that the PC alternative would have the lowest emissions

146 The Company noted that, before upward adjustments for consistency with the project-specific design factors associated with the proposed CFB project, the Wabash heat rate was 8,974 Btu/kWh and the TAG-specified heat rate was 9,600 Btu/kWh (EEC Initial Brief at 139-140, citing, Exh. HO-AG-45A; Tr. 23, at 123-124).

with respect to VOC (id., att. i, Tables 6.3, 6.4). See Table 1. In comparing the natural gas-fired alternatives to the proposed project, EEC indicated that the NGCC and GOCC alternatives would have lower emissions for all pollutants, with the exception of VOCs (id.). In comparing the CGCC alternative to the proposed project, the Company indicated that the CGCC alternative would have lower emissions for all criteria pollutants with the exception of VOCs and CO_2 (id.).

With respect to the MCC alternative, NO-COAL estimated the heat rate to be 8,250 Btu/kWh[147] and provided estimated emission factors based on fuel characteristics, and data from a combustion turbine manufacturer (Exhs. HO-NC-36; HO-NC-35a (att.); Tr. 26, at 59-60).[148] NO-COAL stated that the MCC alternative would not emit SO_2 (Exh. NC-40, at A-8). In addition, NO-COAL estimated that the emission factors for NOx, PM-10, CO, VOC and CO_2 would be less than the emission factors for the proposed project (id.). Finally, NO-COAL noted that emission factors of the MCC plant would be less than the NGCC plant with respect to all pollutants with the exception of CO_2 (Exhs. NC-30; NC-45; atts. 5,6; AG-RE-18, att. i). See Table 1.

(2) Impact of Emissions

a) Criteria Pollutants

With respect to criteria pollutants, EEC asserted that the air quality impacts of the proposed project and the CGCC, NGCC, GOCC, PC and RO alternatives would be minimal

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147 NO-COAL indicated that said heat rate was adjusted for cogeneration and cooling technology consistent with the proposed project (Exh. HO-NC-36).

148 NO-COAL stated that emission factors for NOx and CO were based on information provided in a General Electric marketing information letter dated April 2, 1985 for General Electric combustors fueled by methanol (Exh. NC-35a, att.; Tr. 26, at 59-60). NO-COAL also stated that the CO_2 emission factor for a MCC plant was based on engineering calculations (Tr. 26, at 59-60). NO-COAL noted that additional CO_2 would be produced in the conversion of methane to methanol (Exh. SB-RR-129). NO-COAL indicated that: (1) SCR would not be required to control NOx emissions to 9 ppm; (2) CO emissions would be controlled by combustion efficiency; and (3) methanol is free of sulfur and that firing would not generate particulates (Exh. EEC-NC-34; Tr. 25, at 159; Tr. 26, at 65).

and comparable and would not adversely affect air quality (EEC Brief at 126-137, 144-145). To predict the impact of criteria pollutant emissions on air quality, the Company estimated the percentage of the NAAQS that each facility's emissions would constitute for SO_2, NOx, CO and PM-10 (Exh. AG-RE-18, att. iii at 16-17, att. i, Table 6.4). For the proposed project and each technology alternative, the Company stated that the emissions of each pollutant would constitute an extremely small contribution to ambient concentrations of that pollutant, expressed as a percentage of NAAQS (id., att. iii at 16-17).

For the proposed project, EEC based air quality impacts on the results of the detailed modeling analysis that was performed in support of its air permit application (id., att. iii at 16-17). See Table 3.

For the CGCC, NGCC, GOCC, PC and RO alternatives, the Company based its analysis on: (1) meteorological data consistent with modeling for the proposed project; (2) previously determined emission rates; and (3) assumed facility characteristics including gas flow rates and temperatures, stack diameters and stack heights (id., att. ii).[149]

For the NGCC alternative, the Company's analysis demonstrated that impacts for all criteria pollutants for all averaging periods would be less than the impacts of the proposed project (id.). See Table 3.

For the GOCC alternative, the Company's analysis demonstrated that impacts for all criteria pollutants for all averaging periods, with the exception of annual SO_2 impacts and 24-hour, PM-10 impacts, would be less than the impacts of the proposed project (id.). See Table 3.

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149 The Company indicated that stack heights for all technology alternatives were based on good engineering practice ("GEP") heights, i.e., 2.5 times the height of the tallest facility building (Exh. AG-RE-18, att. ii). The Company indicated that the stack height of the proposed project would be 380 feet and that the stack height of the proposed project also was assumed for the PC alternative (id.; Exh. AG-RE-16, Table 8.5).

For the CGCC alternative, EEC's analysis demonstrated that impacts for all criteria pollutants for all averaging times would be greater than impacts of the proposed project (id.).[150] See Table 3.

For the PC alternative, the Company's analysis demonstrated that impacts for all pollutants for all averaging times would be equal to or less than the impacts of the proposed project (id.). See Table 3.

For the RO alternative, the Company's analysis demonstrated that the one-hour and eight-hour CO impacts would be less than the impacts of the proposed project but that impacts for all other pollutants for all averaging times would be equal to or greater than the impacts of the proposed project (id.).

b) Other Pollutants

EEC asserted that the impacts of CO_2 emissions of the proposed project would be comparable to the CGCC, NGCC, GOCC, PC and RO alternatives (EEC Brief at 137-140). However, EEC also asserted that the CGCC alternative would likely have an adverse air quality impact with respect to emissions of benzene and H_2S (id. at 141-144).

With respect to CO_2, EEC asserted that although CO_2 emissions of the proposed project essentially would be equivalent to emissions of the CGCC, PC and RO alternatives and greater than emissions of the two natural gas-fired alternatives, relative CO_2 emissions impacts of the technology alternatives are not represented by the numerical differences in total emissions (id. at 137). The Company asserted that because there is no ambient air quality standard for CO_2 emissions and no specific information regarding the contribution of CO_2 emissions to overall long-term atmospheric and climatic conditions, a mere comparison

150 The Company indicated that it assumed the same stack height as a NGCC facility for the CGCC alternative, 150 feet, based on the height of a typical heat recovery steam generator building, 60 feet (Exh. AG-RE-18, att. ii; Tr. 22, at 90-91). The Company stated that the gasification process structures would likely be sufficiently far from the combined-cycle process structures so that the gasification process structures would not influence the GEP determination for the combustion turbine stack but that the orientation of structures also would be important in influencing stack height (Tr. 22, at 91-92). The Siting Board notes that local impacts would be greater with lower stack heights.

of the total amount of CO_2 emissions of the various technologies does not result in a meaningful conclusion of their relative CO_2 impacts (id.). In addition, the Company noted that the CO_2 emission increment resulting from operation of the proposed project after NEPOOL backout would be only 26 percent of its total CO_2 emissions (see Section II.B.4.b.ii., below), and that through direct emissions offsets required by the Siting Board in the EEC Compliance Decision, the net emissions of the proposed project would be further reduced (id. at 138).

With respect to emissions of H_2S and benzene, the Company stated that the proposed project would emit negligible quantities of H_2S and that benzene emissions would be below MDEP established (1) 24-hour threshold effects exposure limits ("TEL"), and (2) annual allowable ambient limits ("AAL") (Exhs. EEC-28; HO-2A, p. 5-53; AG-RE-16, Table 8.2).

For the CGCC alternative, the Company calculated likely H_2S and benzene concentrations based on the concentrations and emission rates included in the permit application for the proposed Wabash facility (Exhs. AG-RR-50, AG-RR-51).[151] EEC stated that the results of its analysis demonstrated that the 24-hour average benzene and H_2S concentrations would exceed the TEL and that the one-hour average H_2S concentration also would exceed thresholds for noticeable odor (id.).

With regard to the Company's assertion that TELs would be exceeded for benzene and H_2S emissions, Dr. Breton responded that, for both pollutants, emissions estimates for the Wabash facility were based on site specific information which would not necessarily be accurate for other locations (Exhs. HO-RR-149; HO-RR-150). Dr. Breton also noted that although EEC's analysis demonstrated exceedances when emissions from all facility sources (i.e., three facility stacks and fugitive emissions) were totaled, it would be highly improbable for the maximum concentration from each source to occur at the same receptor (id.).

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151 In estimating benzene and H_2S emissions from the CGCC alternative, EEC scaled the results of a modeling analysis for the proposed 265 MW Destec Wabash facility to account for the differences in plant sizes, assumed annual plant availability and appropriate averaging periods (Exhs. AG-RR-50; AG-RR-51). In estimating such emissions, EEC added potential emissions from the stack for the combined-cycle unit, tail gas incinerator and flare and also fugitive sources (id.).

Further, Dr. Breton stated that EEC overstated estimated fugitive H_2S emissions based on fugitive H_2S emission estimates for the Wabash facility (Exh. HO-RR-150). He noted that the estimates for the Wabash facility did not take into account mitigation measures that would be implemented to control or eliminate fugitive emission sources (id.).

The Company responded that H_2S and benzene emissions predicted for a CGCC facility were based on data derived from predicted emissions at the Wabash facility and are therefore a reasonable indicator of the likely emissions of a CGCC facility at the proposed site (EEC Reply Brief at 71). In addition, EEC noted that H_2S emissions from all sources at the Wabash facility were added in submitting emissions data to the state permitting agencies (id. at 70).

(B) Analysis

In evaluating the comparative air quality impacts of the various technology alternatives, the Company asserted that the appropriate air quality assessment methodology would be to compare modeled emission impacts of the various generating technologies to the NAAQS levels for each of the relevant measurement periods (Exh. AG-RE-18, att. iii at 16-17).

The Attorney General argued that EEC has overemphasized its reliance on the predicted air quality levels as a percentage of ambient standards and that the central question in comparing air quality impacts is, instead, the minimization of impacts (Attorney General Brief at 142-146). First, the Attorney General argued that while the NAAQS are a regulatory standard focusing primarily on local health effects which is an important issue, the environmental policies of the Commonwealth and the nation also are concerned with pollution over a broader area as well as the cumulative effects of emissions on air quality (id. at 143). Second, the Attorney General argued that all effects of pollutant emissions, such as acid deposition, are not addressed by the NAAQS and, in addition, the NAAQS do not cover certain pollutants such as CO_2 (id. at 143-144). Next, the Attorney General argued that the BACT process is not dependent on established regulations, but instead is a technology-driven process to find the best way to minimize emissions from a given fuel and technology (id. at 144). The Attorney General further argued that Siting Board review is not limited to a review of standards imposed by other agencies in that such standards do not necessarily guarantee that a project's environmental impacts have been minimized (id. at 145).[152]

The Attorney General also argued that the Company did not measure impact on the NAAQS in a consistent manner for the proposed project and the technology alternatives in that a refined modeling analysis was performed for the proposed project while only a screening level analysis was performed for the alternatives (id. at 154). The Attorney General further argued that while the screening level analysis may signal potential problems, refined modeling may dispose of all or most of the violations identified under the screening level approach (id.).

The Company responded that an exclusive focus on the quantity of emissions rather than the environmental impacts of the proposed project and technology alternatives is contrary to the minimum impact standard (EEC Reply Brief at 55-56). EEC asserted that raw numbers do not translate directly into environmental impacts and the Siting Board should compare the proposed project and technology alternatives first, on the basis of whether the amount of emissions represents an environmental impact and second, how that impact compares to the impacts of the alternatives (id. at 56).

In comparing the relative air quality impacts of the various technologies, the Siting Board recognizes the significance of considering the impact on local ambient air quality by looking at the percentage of NAAQS that each technology would consume. However, this methodology represents a threshold for comparing air quality impacts. If emissions from a specific technology alternative increased the ambient levels of a pollutant to a level close to or above allowable standards or consumed a significant proportion of allowable standards, the air quality impact of such technology alternative likely would be deemed unacceptable. Here, emissions from all technology alternatives comply with NAAQS by substantial

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152 In addition, the Attorney General argued that environmental externalities are valued by the DPU in tpy and not on the basis of on-ground impacts of specific facilities (Attorney General Brief at 144).

margins. Therefore, the Siting Board's comparison of air quality impacts must encompass more than a review of compliance with the NAAQS.[153]

In addition, the Siting Board has concerns regarding the Company's reliance on an analysis of relative air quality impacts as a percentage of NAAQS. First, the Attorney General correctly states that all impacts of pollutant emissions simply are not addressed by the NAAQS, including (1) the impact of CO_2 emissions, and (2) the effect of criteria pollutant emissions on air quality concerns that are regional or global in nature.[154] Second, the Company's analysis presents the proposed project in isolation relative to ambient standards, and thus ignores the cumulative impact of additional emissions sources that are likely to be constructed in the local area within the 30-year horizon of facility operation. Nevertheless, the Siting Board is sensitive to the Company's position that raw emission data do not translate directly into environmental impacts.[155]

In sum, a comparison of the percent of ambient standards consumed by each technology alternative's contribution to ambient concentrations does provide a context for

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153 In the EEC Decision the Siting Board recognized that Federal and state regulations generally establish quantitative or other specific requirements of acceptability for particular environmental impacts and that compliance with these thresholds does not establish that a facility's environmental impacts have been minimized (22 DOMSC at 334).

154 The Siting Board notes that SO_2 and NOx emissions contribute to acid rain and that NOx and VOC emissions contribute to the formation of ground level ozone. The Siting Board further notes that acid rain is deposited in regions that extend beyond the local area of the point source and that ground level ozone also is transported to regions that extend beyond the local area of the point source.

155 The Siting Board recognizes the Attorney General's concern regarding the consistency of the Company's methodology for analyzing ambient impacts for the proposed project and technology alternatives, in that the Company provided a refined analysis for the proposed facility but a screening-level analysis for the technology alternatives. However, the Siting Board notes that a refined analysis for a technology alternative is an unrealistic requirement to place on a proponent in the context of a comparative technology review.

comparing relative air quality impacts.[156] However, a comparison of the pollutants emitted also provides a reasonable and broader basis for comparing technologies. Therefore, the Siting Board considers both (1) the total amount of pollutants emitted and (2) impacts to local air quality as appropriate measures to compare overall air quality impacts.

In comparing the NGCC alternative to the proposed project, the record demonstrates that emissions of criteria pollutants and CO_2, with the exception of VOC's would be significantly less for the NGCC alternative.[157] In addition, potential improvement in the NGCC heat rate would serve to further reduce facility emissions, thereby increasing the advantage of the NGCC alternative. The record further demonstrates that although the contribution of both the proposed project and NGCC alternative to ambient concentrations would constitute a minimal percentage of ambient standards, ambient impacts nonetheless would be less for the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the air quality impacts of the NGCC alternative would be preferable to the air quality impacts of the proposed project.

In comparing the GOCC alternative to the proposed project, the record demonstrates that although emissions would be slightly higher than emissions of the NGCC alternative, emissions of the GOCC alternative for criteria pollutants and CO_2, with the exception of VOC emissions, also would be significantly less than emissions of the proposed project.[158]

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156 The Siting Board rejects the Company's assertion that air quality impacts are comparable where the contribution to ambient concentrations from the various technology alternatives differ, but are small relative to the NAAQS. A technology alternative that consumes a smaller percentage of the NAAQS for all pollutants would have less environmental impact with respect to air quality, even where differences between technologies are small.

157 The record demonstrates that, compared to the proposed project, the NGCC alternative would emit approximately: (1) 15 percent of the NOx emissions; (2) 0.8 percent of the SO_2 emissions; (3) 33 percent of the CO emissions; (4) 18 percent of the particulate emissions; (5) 56 percent of the CO_2 emissions; but (6) 155 percent of the VOC emissions.

158 The record demonstrates that compared to the proposed facility, the GOCC alternative (continued...)

In addition, ambient impacts of the GOCC alternative would be less for NOx, SO_2 and CO, but would be greater for 24-hour PM-10 standards and equal for annual PM-10 standards. Accordingly, based on the foregoing, the Siting Board finds that the air quality impacts of the GOCC alternative would be preferable to the air quality impacts of the proposed project.

In comparing the CGCC alternative to the proposed project, the Company and the Attorney General presented varying estimates of facility emissions.[159]n However, even with the higher emission factors proposed by the Company, emissions of NOx, SO_2, CO and PM-10 would be less than emissions of the proposed project but VOC and CO_2 emissions would be greater. In addition, ambient impacts, generally, would be greater for the CGCC facility. Even though emission factors for certain criteria pollutants potentially would be less for the CGCC alternative, a significant concern with the CGCC technology is potential emissions of H_2S and benzene. The record demonstrates that emissions of benzene and H_2S from the CGCC alternative could potentially exceed Massachusetts established standards.[160] Therefore, on balance, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to air quality.

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[158](...continued)
would emit approximately: (1) 20 percent of the NOx emissions; (2) 4 percent of the SO_2 emissions; (3) 33 percent of the CO emissions; (4) 37 percent of the particulate emissions; (5) 58 percent of the CO_2 emissions; but (6) 194 percent of the VOC emissions.

[159] The Siting Board notes that expected emissions for a facility are likely to be less than permitted emission rates in order to ensure that permitted levels are not exceeded. The emission factors provided by the Company for the proposed project were the emission rates contained in its draft air permit. The emission factors provided by the Company for the CGCC alternative were based on control technology efficiencies and permit rates while the emission factors provided by the Attorney General were based on expected emission at a proposed facility. Thus, in order to compare the emission factors of the two technologies, the Siting Board relies on the emission factors provided by the Company. The Siting Board notes that the emission factors provided by the Company are less than the permitted emission factors for the Wabash facility for NOx, SO_2 and CO. See Table 2.

[160] The Siting Board notes that estimated emissions of H_2S and benzene are based on anticipated emissions of a proposed facility. See n.151, above.

In comparing the PC alternative to the proposed project, the record demonstrates that emission rates of the PC alternative would be greater for NOx and CO_2, slightly greater for SO_2 and PM-10 and slightly less for CO and VOC. In addition, ambient impacts of the PC alternative would be equal to or less than ambient impacts of the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to air quality.

In comparing the RO alternative to the proposed project, the record demonstrates that emission rates of the RO alternative would be greater for NOx, SO_2 and PM-10, less for CO and CO_2 and comparable for VOC. In addition, the ambient impacts of the RO alternative would be greater for all pollutants with the exception of CO. Therefore, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to air quality.

Finally, in comparing the MCC alternative to the proposed project, the record demonstrates that emissions of criteria pollutants and CO_2 would be less than the emissions of the proposed project. Thus, the Siting Board finds that the MCC alternative would likely be preferable to the proposed project with respect to air quality.[161]

ii. Dispatch

(A) Description

EEC asserted that installation and operation of the proposed project would change the regional dispatch of electric generating units by NEPOOL, which would result in lower regional emissions of several criteria pollutants than without the proposed project, thereby ensuring that the proposed project would have a minimum impact on the environment with respect to air quality (EEC Brief at 140, citing, Exh. HO-AER-43A). In support, the Company provided an analysis indicating that, over the five-year period from 1995 to 1999, operation of the proposed project would result in an average annual net decrease in regional

161 In making this finding, the Siting Board recognizes that estimated emissions were based on engineering calculations, fuel characteristics and data from a combustion turbine vendor and were not substantiated by data from operational or proposed facilities. In addition, no dispersion analysis was provided for the MCC alternative.

emissions of 3,409 tons for SO_2, 2,556 tons for NOx, 262 tons for PM-10 and 9.4 tons for VOC, but an average annual net increase of 1,332 tons for CO (Exh. HO-AER-43A).[162]

To develop its estimates of emissions changes, the Company determined the annual unit-by-unit generation for the region consistent with NEPOOL dispatch procedures, both with and without the proposed project's generation of 2,233.6 gigawatthours ("gwh") (Exh. HO-RR-125).[163,164] The Company's analysis reflected NEPOOL's 1990 CELT Report forecast of annual energy requirements over the period -- an increase of 9,956.5 gwh, from 125,669.7 gwh in 1995 to 135,626.2 gwh in 1999 (id.; Exh. HO-RN-4; Tr. 20, at 183).[165] With respect to supply, the analysis reflected NEPOOL's 1991 CELT Report forecast of annual committed capacity, and assumed that member utilities also would acquire

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162 In response to a request by the Siting Board Staff, the Company prepared an analysis of the impacts of dispatch of a GOCC alternative. In comparing the NEPOOL dispatch of the proposed project to a GOCC facility, EEC assumed that a GOCC facility would displace the same amount of energy from the same resources as the proposed project (Exh. HO-AER-43).

In comparing the emissions displacement of the proposed project to the GOCC alternative, the Company indicated that operation of a GOCC alternative would result in an average annual net decrease in regional emissions of 6,219 tons for SO_2, 3,929 tons for NOx, 391 tons for PM-10, and 235 tons for CO, but would result in an average annual net increase of 42 tons for VOC (Exh. HO-AER-43B).

163 The Company stated that it developed its 1995-1999 dispatch analysis in conjunction with its Siting Council compliance filing made in April 1992 (Exhs. HO-AER-43; HO-65A, Tech. App. II, attached exhibit B). That dispatch analysis was, in turn, a sequel to an earlier dispatch analysis that EEC prepared for the single year 1994, in order to support its claim that the proposed project would provide economic efficiency and environmental benefits (Exh. EEC-8). See EEC Decision, 22 DOMSC at 261-265.

164 Of the 2,233.6 gwh of existing regional generation that would be displaced by the proposed project, an annual average of 1,116 gwh to 1,354 gwh would represent generation by facilities located in Massachusetts (Exh. NC-RR-8).

165 The Company did not use NEPOOL's energy forecast from the then-current 1991 CELT Report (Exh. HO-65; Tr. 20, at 207-208). In the EEC Decision, the Siting Council found that the 1991 CELT Report demand forecast should not be used for evaluating regional need for the proposed project (22 DOMSC at 235-236).

new combustion turbine capacity in sufficient amounts to meet the region's annual peak load capacity requirements (Exhs. HO-RR-125; HO-65; Exh. NC-14; Tr. 20, at 183, 186).[166]

In claiming benefits from displacement of existing generation, EEC stated that its analysis reflected only one actual unit retirement during the 1995-1999 period -- a planned retirement of a 28 MW unit in November, 1995 (Exhs. HO-RR-125; HO-RN-4, rev. at 32; Tr. 28, at 28-29). With respect to dispatch effects on other units, the Company stated that its analysis reflected savings in annual generation for a number of the region's higher cost units once the proposed project or the GOCC alternative is on-line, beginning with 1995 as the first full year (Exh. HO-RR-125; Tr. 28, at 26-27). However, the Company acknowledged that the analysis also shows a year-by-year increase in the annual generation by the same higher cost units over the 1995-1999 period as a result of continuing load growth (Exhs. HO-RR-125; HO-73; Tr. 28, at 17-32).

In terms of fuel mix, the Company's analysis indicated that the generation displaced by operation of either the proposed project or the GOCC alternative would consist almost entirely of existing and planned supply resources using oil or natural gas as a primary fuel (Exh. HO-RR-125).[167] Specifically, the analysis showed projected savings in annual

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[166] The Company used a dispatch analysis methodology generally consistent with that used during the initial EEC review, including: (1) use of a 22.5 percent reserve margin; (2) use of fuel price and unit heat rate estimates assumed elsewhere in the review, including NEPOOL data for existing units and industry data for generic technologies; and (3) development of energy costs based on each unit's average full load heat rate (Exh. EEC-8; Tr. 13, at 154-158, 165-166; Tr. 20, at 182-185, 210-211, 214-215). However, the Company's methodology in its 1995-1999 dispatch analysis incorporated two changes from its earlier methodology (1) it assumed existing committed non-utility generator ("NUG") capacity would be economically dispatched, as distinct from the assumption in the earlier dispatch analysis that such NUG capacity would be "must run" and, therefore, dispatchable ahead of the proposed project, and (2) it assumed that dual-fuel facilities would run on gas for ten months of the year and on oil for two months of the year, rather than eight months on gas and four months on oil as in the earlier review (Exhs. EEC-8; NC-14; HO-RR-125).

[167] As noted above, the Company maintained that the GOCC alternative would have the same displacement effect as the proposed project.

oil-fired generation of 1,352.1 gwh in 1995 increasing to 1,566.3 gwh in 1999 -- savings which account for 60.5 to 70.1 percent of the displacement provided by the proposed project's total annual generation of 2,233.6 gwh (Exh. HO-RR-125; Tr. 28, at 31).[168] The analysis further showed that savings in annual gas-fired generation would account for nearly all of the remaining displacement provided by either the proposed project or the GOCC alternative (Exh. HO-RR-125).

At the same time, the Company's analysis indicated that oil-fired generation will account for a majority of the 1995-1999 increase in annual generation projected by NEPOOL for the region, with or without availability of the proposed project (Exhs. HO-73; HO-RR-125; Tr. 28, at 17-22). Specifically, the Company's analysis reflected increases in oil-fired generation between 1995 and 1999 of 6,813.7 gwh with availability of the proposed project throughout the period, and 7,027.9 gwh without availability of the proposed project, representing 68.4 percent and 70.6 percent, respectively, of the overall 9,956.5 gwh increase in annual generation projected by NEPOOL for that period (id.).[169]

The Company noted that, over the 1995-1999 period, the analysis showed little change in the mix of units that are marginal -- that is, the mix of units that would be displaced by a new low-cost addition (Tr. 24, at 146-147). Mr. La Capra explained that, given current resource planning trends, load growth likely will be met primarily by new base load units

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168 For the first year of its analysis, 1995, the Company indicated that operation of either facility would reduce oil-fired generation from 24,364.5 gwh to 23,012.4 gwh (Exh. HO-73; Tr. 28, at 31). The Company's analysis indicated that, by 1999, annual oil-fired generation would be 29,826.1 gwh with operation of either facility, but would be 31,392.4 gwh without either facility (id.).

169 The Company's analysis also lends itself to consideration of the effect that the proposed project would have on 1995-1999 dispatch trends under a third hypothetical scenario -- one in which it is assumed that the facility will come on-line between 1995 and 1999. The Company's analysis indicates that, under the above assumption, oil-fired generation would increase by 5,461.6 gwh, from 24,364.5 gwh in 1995 to 29,826.1 gwh in 1999 (see n.168, above), representing 54.9 percent of the overall 9,956.5 gwh increase in annual generation projected by NEPOOL for that period (Exhs. HO-73; HO-RR-125; Tr. 28, at 17-22).

and new peaking units, leaving older existing generation at intermediate points in the dispatch order between new base load units and peaking units (id. at 147). He added that "there are a lot of older units to push off" in the dispatch order, and that, therefore, that type of unit will remain marginal for a long time (id.).

While defending the appropriateness of its analysis for demonstrating the emissions backout potential of the proposed project over the 1995-1999 period, the Company noted that it would be necessary to incorporate additional supply options not included in that analysis in order to permanently avoid or minimize emissions increases from the region's existing supply resources (Tr. 28, at 26-30). Mr. La Capra explained that the initial displacement of existing generation and its associated emissions could be made permanent by optimizing the regional supply mix over time -- in particular by continuing to add new lower cost units that would be dispatched ahead of such existing generation (id.). However, the Company noted that, under a logical long-term supply plan, some of the existing intermediate and lesser duration units that initially would be displaced by the proposed project eventually might be replaced by combustion turbine or other peaking units rather than by base load units such as the proposed project (id. at 33-36).

(B) Analysis

The Siting Council previously reviewed the Company's claim, based on a dispatch analysis for the single year 1994, that the proposed project would provide environmental benefits to Massachusetts through displacement of existing generation. EEC Decision, 22 DOMSC at 262-265. While agreeing that the analysis provided evidence of indirect environmental benefits for the region, the Siting Council found that the analysis did not establish that the proposed project would provide guaranteed, quantifiable benefits to Massachusetts because: (1) the analysis assumed that some gas-fired facilities would be "must-run," thereby overstating the potential air emissions benefits; (2) the analysis assumed that gas-oil dual fuel facilities would run on oil for four months of the year, without considering gas availability or air quality permit restrictions on oil use; and (3) the analysis did not determine net air quality impact taking into consideration ambient conditions and dispersion factors in the vicinity of the proposed project. Id. at 264-265.

In a more recent facility case, the Siting Council reviewed a more comprehensive analysis of environmental benefits resulting from dispatch effects of a proposed gas-fired facility. Enron Decision, 23 DOMSC at 69-73. In that dispatch analysis, annual air emissions changes were estimated for four selected years spanning a 20-year period, assuming three alternative expansion plans for meeting regional capacity deficiencies including -- a 100 percent oil-fired combustion turbine expansion plan, an 85 percent gas-fired combined cycle/15 percent oil-fired combustion turbine expansion plan, and an 85 percent atmospheric fluidized bed coal plant/15 percent oil-fired combustion turbine expansion plan. Id. at 45-48, 70. The Siting Council found that the proposed project in that review would provide Massachusetts with environmental benefits related to net changes in air emissions from generating facilities in Massachusetts. Id. at 73.

Here, the Company has expanded the time frame of its earlier 1994 dispatch analysis to address the five-year period 1995-1999. The Company also has separated out the dispatch effects on Massachusetts generating facilities, thereby documenting that Massachusetts will share significantly in the regional environmental benefits demonstrated by the dispatch analysis. Finally, the Company has changed its dispatch analysis methodology to both assume economic dispatch of gas-fired NUG facilities and assume ten months of gas firing at dual-fuel facilities, thereby substantially addressing two of the three concerns raised by the Siting Council in its review of the Company's 1994 dispatch analysis.

Thus, the Company's 1995-1999 dispatch analysis comes much closer than its earlier 1994 dispatch analysis to providing the level of documentation required to support a claim of environmental benefits based on dispatch effects of the proposed project. Viewed in the context of a few initial years of operation after the facility comes on-line, beginning with 1995, the Company's analysis provides a reasonably realistic basis to conclude that both Massachusetts and New England as a whole would receive air quality benefits reasonably attributable to the proposed project.

Viewed over the life of the project, however, the Company's analysis falls short of providing a realistic basis to attribute long term environmental benefits to the proposed project. Unlike the analysis reviewed in the Enron decision, the Company's analysis fails to span a reasonable long term-time frame, such as 20 or 30 years, and fails to reflect possible capacity expansion plans in the region incorporating technologies other than oil-fired combustion turbine units.

As a result of its extended scope -- five years versus the single-year analysis reviewed in the EEC Decision -- the Company's 1995-1999 dispatch analysis begins to reveal the inadequacy of the Company's framework for addressing possible long-term environmental benefits. Under the framework, the dispatch analysis shows that, if built, the proposed project's annual generation would account for less than one quarter of the four-year 1995-1999 increase in annual regional generation. At the same time, oil-fired generation, primarily existing units and new combustion turbine units, would account for at least 54.9 percent of the regional increase, assuming the proposed project comes on-line between the first and last years, and as much as 68.4 percent, assuming the proposed project is already on-line at the beginning of the first year of the analysis.

Recognizing that natural gas, coal or other fuels besides oil currently are "fuels of choice" for new base load units, the Siting Board must question the applicability of a dispatch analysis that assumes such fuels of choice would account for less than half of the growth in annual regional generation over four years. Assuming, further, that fuels of choice for new base load units would have emissions characteristics generally matching or surpassing those of the proposed project, any failure to adequately represent those fuels of choice would suggest that the Company's analysis may have overstated the emissions which would be displaced by the proposed project.

We recognize that, as mentioned above, the Company's analysis may have applicability in posing certain short-term questions, for example in assessing whether implementation of the proposed project one year earlier would provide environmental benefits. Even the five-year analysis, were it intended to represent a period of capacity surplus in the region, might provide a technically reasonable basis for assessing environmental benefits over that period. However, the Company is not maintaining that the first five years of operation of its proposed project represent a period of capacity surplus.

Beyond the 1995-1999 time frame of the Company's dispatch analysis, the long term applicability and relevance of the results of the analysis diminish quickly, assuming load in the region continues to increase. As acknowledged by the Company, it would be necessary to continue to add new low cost units, which would be dispatched ahead of existing generation, in order to optimize the regional supply mix in a manner likely to permanently avoid or minimize emissions increases. Clearly, a regional generation expansion plan that includes a substantial mix of base load units, not just combustion turbine units as assumed in the Company's analysis, is likely to meet cost and reliability objectives as well.

Thus, the Company presents a five-year dispatch analysis that reflects, in large part, the environmental benefits of displacing intermediate and peaking units, and then notes that a series of new base load units must be added over time to maintain the displacement of those intermediate and peaking units. In effect, then, such displacement may be viewed as simply cyclical, not a valid basis for claiming a long-term benefit. Even if the initial displacement, as reflected in the Company's analysis, is viewed as a long-term benefit, it must be viewed as shared by the series of base load units that is required to maintain the benefit over time.

Accordingly, the Siting Board finds that the Company's dispatch analysis establishes that the proposed project likely would provide short-term air qualilty benefits for Massachusetts and New England based on the modeled dispatch effects. The Siting Board further finds that the Company's dispatch analysis does not establish that the project would provide significant long-term air quality benefits based on the modeled dispatch effects.

Despite its finding that the Company's dispatch analysis did not demonstrate long-term environmental benefits, the Siting Board recognizes that, with adjustments to reflect more realistic assumptions about the future supply mix and associated emissions for Massachusetts and New England, the outcome of the Company's dispatch analysis would have been different. As mentioned, the Company's analysis did not reflect the addition of other potential but presently uncommitted base load units, even though Mr. La Capra acknowledged that the addition of such units over the long run would optimize the supply mix. Had the Company presented an analysis that reflected potential addition of such base load units, it might have reflected a scenario in which base load generation would maintain or increase its share of total generation over time, increasing the possibility for a showing of long-term environmental benefits.

In addition, two other assumptions underlying the Company's five-year dispatch analysis may be unrealistic if viewed in a longer-term context. First, the analysis assumed constant emission rates, in lbs/MMBtu, over time. Second, the analysis reflected limited retirement of existing generation -- one 28 MW unit -- over the five-year period. While the above assumptions are understandable, given uncertainties underlying both issues, they may not represent the most realistic expectations.

The Siting Board notes that the Massachusetts State Energy Plan incorporates long-term expectations and policy positions that differ from the above assumptions in the Company's five-year analysis.[170] First, the State Energy Plan provides that electric utilities likely will face tightened air pollution restrictions as a result of forthcoming state implementation of requirements of recent federal Clean Air Act amendments. Second, the State Energy Plan posits that accellerated retirement of older generating units could be the least-cost option for future energy supply. Based on the above, the State Energy Plan recommends use of competitive bidding for least-cost generating facility compliance with the Clean Air Act.

The record demonstrates that, considering relative emission rates and heat rates, many generating units in the existing supply mix have a per-kwh emission impact well above that of the proposed project for important pollutants, such as SO_2 and NOx. That relative advantage is demonstrated in the early-year results of the Company's dispatch analysis, which the Siting Board has found to be valid. Assuming consideration of a future supply mix that reflects the potential for significant retirement of existing generating units, consistent with policy recommendations in the State Energy Plan, a long-term dispatch

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170 The Massachusetts Energy Plan was issued by the Massachusetts Division of Energy Resources in April, 1993, after the close of hearings in the remand proceedings. The Hearing Officer took official notice of the document at the request of the Attorney General to show the fact that the Commonwealth has made the statements and articulated the policies contained therein. The Hearing Officer, however, refused to notice the document for the truth of any statements contained therein.

analysis of the type presented by the Company very well could show long-term environmental benefits attributable to replacement base load capacity using any of a variety of technologies, including that of the proposed project.

Thus, although the Company's dispatch analysis failed to demonstrate long-term environmental benefits, the record in this proceeding does not support a conclusion that the project is unlikely to provide long-term environmental benefits based on displacement of existing generation. Rather, state policy as reflected in the State Energy Plan supports a conclusion that accellerated retirement of existing generation much of which produces significantly higher emissions per kwh than the proposed project, very well may be a viable and appropriate course.

Accordingly, the Siting Board recognizes that, to the extent the proposed project, in whole or in part, effectively would replace existing generation that potentially will be permanently retired, there is a significant potential for the proposed project to provide long-term environmental benefits through displacement of such generation.

The Siting Board takes administrative notice of the recently promulgated Department of Environmental Protection regulation 310 C.M.R. 7.00 Appendix B on Emission Banking, Trading, and Averaging. The purpose of this regulation is to establish a program of emission banking and trading for NOx, VOC and CO whereby persons and companies who reduce emissions below levels required by state and federal regulations can "bank" the surplus reduction for use at a later date or transfer the reduction to another party. The regulation must be approved by the U.S. Environmental Protection Agency as part of a revision to the Massachusetts State Implementation Plan to become fully effective.

In order to help ensure that the findings in this decision regarding net emissions reduction benefits of NOx and VOC for the Massachusetts emissions inventory are realized if the proposed facility is constructed, the Siting Board strongly encourages Eastern Energy Corporation to make use of the emerging emission reduction trading market. In this regard, the Siting Board recommends that prior to construction of the proposed Eastern Energy facility, the Company reassess the plant's net emissions effects in Massachusetts for NOx and VOCs and obtain emission reduction credits ("ERCs") as may be necessary to ensure a net emissions benefit for each pollutant that will assist the Commonwealth in meeting the requirements of the Clean Air Act Amendments of 1990. This recommendation is subject to the availability of an approved emissions trading regulation under 310 C.M.R. 7.00 Appendix B or any potential successor to this regulation.

c. Water Supply and Wastewater

i. Water Supply

(A) Description

The Company indicated that large quantities of water would be required for each of the technology alternatives, primarily for boiler water makeup and air pollution control (Exh. AG-RE-18, att. iii at 20).[171] EEC asserted that the water supply impacts of the proposed project and the NGCC, GOCC, RO and PC alternatives would be comparable, but that the water supply impacts of the CGCC alternative would be greater than other alternatives (EEC Brief at 145-148).

With respect to the proposed project, EEC stated that water supply requirements have been minimized by facility design which includes (1) an air-cooled, rather than water-cooled, condenser, and (2) recycling of internal boiler blowdown (Exh. AG-RE-18, att. iii at 19). The Company stated that facility design would be consistent with the goals of the Commonwealth regarding the conservation of water resources (Exh. HO-E-12A at 1-22).[172] The Company estimated that the proposed project would require 306,700 gallons per day ("gpd") for boiler makeup but would not require water for air pollution control (Exh. AG-RE-18, att. iii at 21).

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171 EEC assumed that other, less significant water uses, such as equipment washes and fire protection, would be constant for all alternatives (Exh. AG-RE-18, att. iii at 20). In addition, EEC assumed that water makeup for condensate not returned by steam hosts would be identical for each option (id.).

172 The Company indicated that approximately one-half of its water requirements would be met by utilization of treated wastewater from neighboring facilities and one-half by City of New Bedford municipal water (Exh. HO-12A at 1-21).

In estimating the water supply requirements for the technology alternatives, the Company assumed the same water minimization features as would be incorporated into the proposed project (id., att. iii at 20).

With respect to the NGCC alternative, the Company estimated that water requirements would total 401,800 gpd -- 285,200 for steam injection to suppress NOx formation[173] and 116,600 for boiler feedwater (id., att. i, Table 6.5, att. iii at 21-22). The Company based its estimate of water requirements on the water balance for an existing facility that supplies steam to a steam host and utilizes steam injection with SCR to control NOx emissions (id., att. ii).

EEC stated that the combination of steam injection and SCR for NOx control is commercially available from several vendors for use in large combustion turbines (Exh. HO-AER-14).[174] EEC stated that the MDEP has recently approved steam injection and SCR as BACT for two natural gas-fired, combined cycle facilities (id.). However, EEC also stated that several manufacturers have recently announced plans to introduce dry low-NOx combustors, capable of controlling NOx emissions without steam injection (id.). EEC noted that a permit has been requested from the MDEP for a natural-gas fired cogeneration facility that would utilize dry low-NOx technology rather than steam injection (id.; Tr. 22, at 87).

The Attorney General argued that dry low-NOx combustors are available for use on turbines firing natural gas thereby reducing estimated water supply requirements by 285,200

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173 EEC indicated that SCR also would be required for NOx control (Exh. AG-RE-18, att. ii). See Section II.B.4.b, above.

174 EEC stated that this technology would limit NOx emissions to 9 ppm, consistent with Northeast States for Coordinated Air Use Management ("NESCAUM") guidance for permitting new combustion turbines (Exh. HO-AER-14). EEC stated that this was the only technology available to meet this NOx emission limit at the time the alternatives analysis was originally prepared (id.).

gpd (Attorney General Brief at 149-150).[175] Thus, he argued that impacts to water supply would be significantly less for the NGCC alternative than the proposed project (id.).

With regard to the GOCC alternative, the Company stated that water requirements would total 436,300 gpd -- 319,700 gpd for steam injection for NOx control and 116,600 gpd for boiler feedwater (Exh. AG-RE-18, att. i, Table 6.5). The Company stated that, even if dry low-NOx combustors were utilized, the same steam injection would be required during periods of distillate oil firing (Exh. HO-AER-14).[176]

With respect to the CGCC alternative, EEC stated that water requirements would be 1,166,400 gpd -- 116,600 gpd for boiler makeup and 1,049,800 gpd for air pollution control (id., att. i, Table 6.5). EEC stated that air pollution controls requiring significant water supply would include (1) 285,200 gpd for steam injection into the turbine combustor to suppress NOx formation, and (2) 764,600 gpd for an integral wet scrubber for particulate control (id., att. i, Table 6.5, att ii, att. iii at 21-22; Tr. 22, at 52). The Company assumed water requirements for the boiler feedwater and steam injection would be equivalent to the water requirements of the NGCC alternative and estimated water requirements for the integral wet scrubber based on 1989 TAG data (id., att. ii).

The Attorney General argued that the Company overstated the water requirements of the CGCC alternative (Attorney General Brief at 188-191). First, the Attorney General argued that the CGCC alternative would not require steam injection to control NOx emissions

175 The Attorney General argued that successful use of dry low-NOx burners with gas turbines in lieu of steam injection was confirmed in an article written by a gas turbine vendor (Attorney General Brief at 149, citing, JH-RR-7, exh. 1).

176 The Siting Board notes that 1/6 of the annual water requirements for steam injection, based on oil firing for 2 months per year, would equal approximately 15 million gallons per year (Exh. HO-AER-44). Thus, the annual water requirements for the GOCC alternative with dry low-NOx combustors would be 51.2 million gallons per year while the annual requirements of the proposed project would be 95.2 gallons per year (id.; Exh. AG-RE-18, att. i, Table 6.5).

given the availability of dry, low-NOx burners (id. at 189-190).[177] Dr. Breton estimated that water requirements of a CGCC facility, without steam injection, would be 166,600 gpd -- 116,600 gpd for boiler feedwater and 50,000 gpd for other requirements including the coal slurry makeup (Exhs. AG-201, at 14; EEC-AG-44).[178] Dr. Breton stated that a dry particulate removal system, replacing the wet particulate removal system, has recently been installed in the LGTI facility but is not yet operational (Tr. JH2 at 134). He noted that the dry particulate removal system uses less equipment and has cost advantages relative to the wet particulate removal system (id. at 143-145). He further noted that a dry particulate removal system also is proposed for the Wabash facility (id. at 146).

The Company responded that, although the application of dry low-NOx burners on gas turbines firing syngas theoretically would be possible, application of dry low-NOx combustion technology to syngas, instead of steam injection, has not been demonstrated (Exh. AG-RR-53; Tr. 22, at 43, 55). The Company's witness, Mr. Slack, added that, even without steam injection, the CGCC facility still would require approximately 881,200 gpd, more than the water requirements of any of the other technologies (Exh. AG-RE-18, att. i, Table 6.5; Tr. 22, at 52). Finally, EEC asserted that the Attorney General provided no basis for his estimate that a CGCC facility would require only 50,000 gpd in addition to boiler feedwater, noting that a dry particulate removal system has not yet been utilized on an operating CGCC facility (EEC Brief, n.81, citing, Tr. JH2, at 73-74).

EEC stated that water requirements of the PC alternative would total 449,300 gpd -- 143,600 gpd for air pollution control (dry scrubbing system) and 306,700 gpd for boiler

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177 Dr. Breton stated that he was aware of two gas turbine vendors that would supply dry low-NOx burners for operation on syngas (Tr. JH2, at 36-38). In addition, Dr. Breton stated that a new CGCC facility in the Netherlands will utilize dry low-NOx burners along with nitrogen dilution to control NOx emissions below 20 ppm (id. at 36). However, Dr. Breton also stated that the existing LGTI facility does not utilize dry low-NOx combustor technology (id. at 120).

178 Dr. Breton stated that water requirements for the gasification process also would depend on the moisture content of the coal (Exh. AG-210, at 14).

feedwater and that water requirements of the RO alternative would be 306,700 gpd for boiler feedwater only (Exh. AG-RE-18, att. i, Table 6.5, att. iii at 21).

Finally, with regard to the MCC alternative, NO-COAL stated that water requirements would not differ significantly from the NGCC or GOCC alternatives (Exh. HO-NC-40, at A-7). In addition, NO-COAL stated that provisions could be made for water-injection as a stand-by measure to maintain the NOx emission rate (Exh. HO-NC-35).

(B) Analysis

In comparing the water requirements of the proposed project to the NGCC alternative, the Company assumed that the NGCC alternative would utilize steam injection and SCR for NOx emission control inasmuch as such technology would: (1) provide adequate NOx emission control; (2) was commercially available for use in large combustion turbines, (3) had been approved as BACT, and (4) was incorporated into the design of current projects. The Siting Board notes, however, that there is significant variation in the overall water requirements of the NGCC alternative, depending on the choice of NOx control -- steam injection with SCR or dry low-NOx technology. The NGCC alternative would use approximately 31 percent more water than the proposed project with steam injection and SCR but approximately 62 percent less water than the proposed project with dry low-NOx technology. Although the record demonstrates that recently proposed natural gas-fired plants in Massachusetts incorporate both technologies, the record does not provide information regarding the considerations that would lead a developer to choose to install dry low-NOx technology over steam injection (i.e., water constraints at the site, permit requirements) nor does the record provide information regarding potential impacts of the dry low-NOx technology to overall facility cost, heat rate or power output. Thus, the record does not demonstrate that dry low-NOx technology would be the likely NOx control technology for the NGCC alternative at the proposed site. Further, based on the information available to the Company at the time of filing, the Company reasonably assumed that the NGCC alternative would incorporate steam injection with SCR. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the NGCC alternative with respect to water supply impacts.

With respect to the GOCC alternative, the record demonstrates that the GOCC alternative also would require approximately one-half of the water supply of the proposed project for boiler feedwater. Use of steam injection for NOx control increases water requirements such that the GOCC alternative would use 42 percent more water than the proposed project. If dry low-NOx technology were assumed, steam injection would be limited to periods of oil firing. Steam injection water requirements would be reduced by at least five-sixths and overall water requirements would be approximately 55 percent of those of the proposed project. However, for the same reasons noted above in comparing the water supply requirements of the NGCC alternative to the proposed project, it is reasonable to assume for the purposes of this review that steam injection would be incorporated into GOCC facility design. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to water supply impacts.

In comparing the proposed project to the CGCC alternative, the record demonstrates that water requirements of the CGCC alternative for boiler feedwater and coal slurry, exclusive of water for air pollution control, would be approximately 54 percent of the water requirements of the proposed project. With respect to air pollution control, the Company assumed technologies that have been utilized in existing CGCC facilities -- steam injection for NOx emission control and a wet particulate removal system which would increase water requirements of the CGCC alternative. For the same reasons stated above in comparing the water supply requirements of the NGCC alternative to the proposed project, it is reasonable to assume, for the purposes of this review, that steam injection would be incorporated into the design of the CGCC alternative.[179] However, with regard to particulate control, the record demonstrates that, although not yet operational, a dry particulate removal system has

[179] The Siting Board notes that although dry low-NOx combustor technology has been incorporated into the design of one new CGCC facility in the Netherlands, NOx emissions of that facility will be controlled to 20 ppm whereas control to 9 ppm would be consistent with NESCAUM guidelines and likely required for operation in Massachustts by the MDEP (see n.174, above).

been installed in one existing CGCC facility and is proposed for an additional facility. In addition, the record demonstrates that the dry particulate removal system likely would have a cost advantage relative to the wet particulate removal system. Thus, it is reasonable to assume, for the purposes of this review, that a dry particulate removal system would be incorporated into the design of the CGCC alternative.

Therefore, assuming steam injection and a dry particulate removal system, and including water requirements for coal slurry makeup, the water requirements of the CGCC alternative would be 451,800 gpd, approximately 47 percent greater than the water requirements of the proposed facility. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to water supply impacts.

With regard to the PC and RO alternatives, the record demonstrates that the PC alternative would require more water than the proposed project and the RO alternative would have comparable requirements to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the PC alternative with respect to water supply impacts and the proposed project would be comparable to the RO alternative with respect to water supply impacts.

Finally, with regard to the MCC facility, NO-COAL assumes that water supply requirements would be equivalent to the NGCC alternative. However, the record contains no evidence of the type of combustion technology that would be used to control NOx emissions, and of the feasibility or water requirements of using water injection as a stand-by measure to insure NOx emission limitations. Therefore, the Siting Board can make no finding regarding the relative water supply impacts of the proposed project and the MCC alternative.

ii. Wastewater

The Company indicated that the wastewater generated by the proposed project and the CGCC, NGCC, GOCC, RO and PC technology alternatives would primarily consist of boiler blowdown and air pollution control system purge (Exh. AG-RE-18, att. iii at 22). The Company indicated that wastewater impacts of the proposed project and the NGCC, GOCC, RO and PC alternatives would be comparable but that the wastewater impacts of the CGCC alternative would be greater than the other alternatives (id. at 22-23).

With respect to the proposed project, EEC stated that wastewater impacts would be minimal (id.). The Company explained that: (1) boiler blowdown wastewater would be minimized through a recycle system; (2) air pollution control would not produce wastewater; and (3) only minimal quantities of wastewater would be generated from cooling equipment (id.).

In estimating wastewater generation of the technology alternatives, the Company assumed use of similar cooling technology and internal wastewater recycling as was assumed for the proposed project (id. at 22). With regard to the NGCC and GOCC alternatives, EEC stated that water would be utilized for air pollution control but that it would be evaporated in the combustion turbine (id.). The Company stated that, therefore, wastewater generation would be comparable to the proposed project (id.).

With regard to the CGCC facility, EEC estimated that, given the wastewater generated by the integral wet scrubber system, total facility wastewater would be 200,000 gpd greater than that generated by the proposed project (id. at 23).

For the PC alternative, EEC stated that water utilized for air pollution control also would be evaporated (id.). Finally, the Company noted that the RO alternative would not require water for air pollution control (Exh. HO-AER-44).

In comparing the wastewater impacts of the proposed project to the NGCC, GOCC, CGCC, PC and RO alternatives, the record demonstrates that internal wastewater of all technologies could be recycled.

The record further demonstrates that additional water required for air pollution control for the NGCC, GOCC and PC alternatives would be evaporated and that additional water would not be required for air pollution control for the RO alternative. Accordingly, based on the foregoing the Siting Board finds that the proposed project and the NGCC, GOCC, PC and RO alternatives would be comparable with respect to wastewater impacts.

With respect to the CGCC alternative, the record demonstrates that the integral wet scrubber system could be replaced by a dry particulate removal system. See Section

II.B.4.c.i, above. Thus, the CGCC alternative would not generate 200,000 gpd of wastewater over the amount generated by the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the CGCC alternative would be comparable with respect to wastewater impacts.

With respect to the MCC alternative, it is likely that boiler feedwater recycling would be comparable to boiler feedwater recycling within the other combined cycle technologies -- NGCC, GOCC and CGCC. In addition, any water required for air pollution control would be evaporated. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the MCC alternative with respect to wastewater impacts.

d. Noise

i. Description

The Company asserted that the noise impacts of the proposed project and the NGCC, GOCC, RO and PC alternatives would be comparable but that the noise impacts of the CGCC alternative would be greater than other alternatives (EEC Brief at 153).

With respect to the proposed project, the Company stated that major noise sources would be the air-cooled condenser, fans, coal processing and rail car operations (Exh. AG-18, att. i, Table 6.7). The Company stated that noise mitigation features have been incorporated into the design of the facility, including (1) noise controls on major equipment, and (2) layout of facility components to shield major noise sources (Exh. HO-65B, secs. 2, 4.1). EEC indicated that the sound power level of major noise sources, exclusive of coal processing and rail car operations, would range from 122 decibels ("dBA") to 130 dBA before mitigation and from 95 dBA to 117 dBA after mitigation (id., Table 4-1).[180] The Company further indicated that maximum noise increases at the closest residence, located

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180 The Company indicated that sound power levels of the most significant noise sources, exclusive of the locomotive and coal unloading, had been reduced since the original filing to levels included in the compliance filing as follows: (1) air cooled condenser, 129 dBA to 117 dBA; (2) induced draft fans, 127 dBA to 107 dBA; (3) forced draft fans, 122 dBA to 104 dBA; and (4) fluidizing air blowers, 130 dBA to 95 dBA (Exh. HO-65B, Table 4-1).

4,520 feet from the facility stack, would be 6 dBA during daytime hours and 2 dBA during nighttime hours (id., Table 4-5, Table 5-1). Finally, the Company indicated that maximum noise increases at the northern property line, located 1,920 feet from the facility stack, would be 10 dBA during daytime hours and 9 dBA during nighttime hours (id.).

With respect to the technology alternatives, the Company stated that major noise sources would be: (1) the air cooled condenser for all alternatives; (2) coal processing for the coal-fueled alternatives, CGCC and PC; (3) rail car operation for the PC, GOCC, CGCC and RO alternatives; and (4) gas turbine exhaust and gas turbine inlet for the combined-cycle alternatives, NGCC, GOCC and CGCC (Exh. AG-RE-18, att. i, Table 6.7).

The Company indicated that noise impacts of the NGCC alternative would be comparable to the impacts of the proposed project (Exhs. AG-RE-18, att. iii at 28; HO-AER-45). Based on noise emission data for an existing NGCC facility and noise emission data for the EEC air-cooled condenser, the Company estimated that site-specific noise impacts would be (1) five dBA during daytime hours and two dBA during nighttime hours at the nearest residence, and (2) seven dBA during daytime hours and eight dBA during nighttime hours at the northern property line (Exh. HO-AER-45, Table AER-45A). EEC stated that, therefore, the NGCC alternative would be slightly quieter than the proposed project but that the difference in noise level increases between the NGCC alterntive and the propsed project would not be noticeable at the nearest residence (Exh. HO-AER-45).

EEC noted that a high degree of noise controls was required for the NGCC facility referenced above due to its close proximity, approximately 800 feet, to residences, without a buffer comparable to the proposed site (id.). The Company added that it is unlikely that noise emissions from the NGCC alternative could be significantly reduced, consistent with minimization of cost, such that the difference in ambient noise levels of the two alternatives would be noticeable (id.).

With regard to the GOCC alternative, the Company indicated that the noise characteristics would be comparable to the NGCC alternative with additional noise associated with periodic rail shipments of oil (id.).

With respect to the CGCC alternative, EEC indicated that noise impacts would be significantly greater than the proposed project (Exh. HO-RR-111, sup.). EEC stated that additional major sources of noise, in addition to sources common to other technologies, would include flaring operations, the gasification process and the air separation process (id.).[181] Based on existing noise levels of components of the gasification and air separation processes at the LGTI facility, EEC estimated that, the sound power level of an air separation plant would be 121 dBA and the sound power level of a gasification plant would be 125 dBA (id.).[182] Then, based on estimated sound power levels and site data, the Company calculated that site specific noise increases would be (1) 14 dBA during daytime hours and 10 dBA during nighttime hours at the closest residence, and (2) 19 dBA during daytime hours and 20 dBA during nighttime hours at the northern property line (id.).[183]

The Attorney General argued that the Company's estimation of CGCC noise emissions were inaccurate and that the noise impacts of the CGCC alternative would be comparable to the proposed project (Attorney General Brief at 194-196). The Attorney General argued that a noise study performed for the Wabash facility was more reliable than the Company's

181 EEC noted that the coal gasification component, which is a highly pressurized process, would not be fully enclosed in a manner similar to the CFB process (Tr. 22, at 57, 119).

182 The Company based its noise assessment on noise emission data provided by Dr. Breton on a simplified plot plan of components of the LGTI facility (Exhs. HO-RR-111; EEC-AG-12). The Company indicated that, in order to estimate noise impacts for a 300 MW CGCC facility based on the noise emission data provided, it assumed a distance scale for facility components and also assumed that noise power levels were representative of near-field conditions (Exh. HO-RR-111).

183 EEC indicated that noise increases would be greater during flaring episodes which would occur during facility start-ups and emergency conditions (Exh. HO-RR-111, sup.; Tr. 22, at 163-164; Tr. JH2, at 122-123). Based on engineering calculations, the Company estimated that the noise emission level of a flaring episode would be 127 dBA (Exh. HO-RR-111, sup.). The Company calculated that noise increases, with flaring, would be 22 dBA during the day and 18 dBA during the night at the nearest residence and 23 dBA during the day and 24 dBA during the night at the northern property line (id.).

extrapolation of LGTI data (id. at 194). He stated that such study, which was based on the Wabash site plan and terrain with LGTI noise data, predicted gasification plant noise emissions of 95 dBA at a five foot distance from the facility, and 43.4 dBA at a 1,900 foot distance, significantly less than those predicted by the Company (Exh. SB-JH-RR-15, exh. 1).

The Attorney General also argued that EEC's assumptions relative to the LGTI noise data likely would lead to erroneous conclusions (Attorney General Brief at 194-195).[184] Finally, the Attorney General argued that noise mitigation could be incorporated into the design of a CGCC facility (id. at 195-196). Dr. Breton stated that the LGTI facility was designed for operation within a large chemical complex and that, therefore, strict noise emission criteria was not imposed on facility design (Exh. HO-RR-148). However, he stated that equipment could be designed with features such as vent silencers and acoustic enclosures in order to minimize noise emissions (id.).[185]

With regard to the PC alternative, EEC stated that noise sources would be similar to those of the proposed project with two additional noise sources -- coal pulverizers and the flue gas desulfurization system (Exh. AG-RE-18, att. iii at 27-28). However, the Company stated that the noise level of the PC alternative would still be comparable to the noise level of the proposed project (id.).

Finally, with regard to the RO alternative, EEC stated that noise sources also would be similar to those of the proposed project, but because there would not be any coal processing sources, the overall noise level would be slightly less than the proposed project (id., at 29).

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184 Dr. Breton explained that the facility layout on which the noise survey was presented was not to scale and that the noise measurements included both near and far field source data (Exh. HO-RR-148).

185 Dr. Breton indicated that although portions of the gasification process would not be enclosed, noise emissions could be reduced by construction of a brick wall around the gasifier or enclosure of certain significant noise sources such as the rotating slurry pumps (Tr. JH2, at 46-47; Tr. JH3, at 62-63).

With respect to the MCC facility, NO-COAL stated that noise impacts would be comparable to the NGCC alternative (Exhs. EEC-NC-8; NC-40, at A-7).

ii. Analysis

In comparing the noise impacts of the proposed project and the NGCC alternative, the record demonstrates that the NGCC alternative would be slightly quieter -- one dBA quieter during daytime hours at the nearest residence, three dBA quieter during daytime hours at the northern property line, and one dBA quieter during nighttime hours at the northern property line. However, the record also demonstrates that the Company's analysis was based on an existing NGCC facility that is located in close proximity to residences, without the buffer that exists at the proposed site. As such, the analysis was based on a facility that likely was required to incorporate a high degree of noise control measures, which might not be required at the proposed site. Even though the study concluded that the noise impacts of the NGCC alternative would be slightly less than the noise impacts of the proposed project, such a slight reduction in noise would not be noticeable to residents in the vicinity of the proposed site. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the NGCC alternative with respect to noise impacts.

With respect to the GOCC alternative, the record demonstrates that noise impacts would be similar to the noise impacts of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the GOCC alternative with respect to noise impacts.

In comparing the proposed project to the CGCC alternative, the record demonstrates that sound power level of the major noise sources, prior to incorporation of mitigation measures, would be comparable. However, in comparing facility components of the two technologies, the record demonstrates that greater mitigation likely would be achieved for the proposed project. Specifically, the components of the CFB facility would be completely enclosed while certain portions of the coal gasification process, which is a major source of noise, would be open, and a flare stack would be required only for the CGCC alternative. The Siting Board notes that noise mitigation measures, i.e., silencers, partial enclosures and shielding within the site, can be incorporated into the design of the CGCC alternative to reduce noise of the open components. However, because these components must remain open, mitigation measures would not necessarily be as effective as they would be for fully enclosed components.

In addition, the Siting Council notes that the flare stack potentially would be an added noise source of significance for the CGCC alternative. The noise emission level of a flaring episode would be comparable to the sound power level of the significant noise sources at both facilities, before mitigation. By virtue of the height of the stack, it is unlikely that the flare stack noise could be shielded by other facility components. In addition, there is no indication in the record that flaring episodes could be limited to specific time periods when the impacts would be reduced.[186]

Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to noise impacts.

With respect to the PC alternative, the record demonstrates that the overall noise level would be comparable to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to noise impacts.

With respect to the RO alternative, the record demonstrates that the overall noise level would be slightly less than the overall noise level of the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the RO alternative would be slightly preferable to the proposed project with respect to noise impacts.

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[186] In comparing the noise impacts of the proposed project and the CGCC alternative, the Siting Board does not rely on the Company's noise analysis based on LGTI data or Wabash data provided by the Attorney General. With regard to the Company's noise analysis, the Siting Board notes that (1) possible erroneous assumptions regarding locations of measurements and distances to major sources may have skewed estimates of sound power levels, and (2) the LGTI facility is located within a large chemical complex, and thus, minimization of noise emissions would not be of primary concern. With respect to the noise study of the proposed Wabash facility, the Siting Board notes that it was based on site-specific terrain and configuration of facility components and terrain and, therefore, would not be transferable to a CGCC facility located at the proposed site.

Finally, with respect to the MCC alternative, the record demonstrates that noise impacts, if fuel were delivered by pipeline, would be comparable to the NGCC alternative. However, the record also demonstrates that rail transport of fuel would require daily fuel delivery. The Company's analysis of the proposed project demonstrates that rail delivery of fuel is a significant noise source and five trains would be required weekly. Thus, with rail delivery of fuel on a daily basis, the noise impacts of the MCC alternative potentially would be greater than the noise impacts of the NGCC alternative and noise impacts would be, at best, comparable to the noise impacts of the proposed project. However, because fuel transport to the MCC alternative is uncertain, noise impacts also would be uncertain. Accordingly, based on the foregoing, the Siting Board can make no finding regarding the relative noise impacts of the proposed project and the MCC alternative.

e. Solid Waste

i. Description

EEC stated that the coal-based technology alternatives would generate greater quantities of solid waste than the gas or oil-based technologies due to (1) the ash content of coal, and (2) air pollution control processes (Exh. AG-RE-18, att. i, Table 6.6, att. iii at 23-24). However, the Company asserted that none of the technology alternatives would have an impact with respect to solid waste disposal in Massachusetts landfills and, as such, the solid waste impacts of the proposed project and the CGCC, NGCC, GOCC, RO and PC alternatives would be comparable (EEC Brief at 149).

The Company stated that operation of the proposed project would generate approximately 260,000 tpy of solid waste due to the combustion of coal and addition of limestone[187] which would be transported back to the coal production area via rail and used to back-fill the local mines (Exh. AG-RE-18, att. iii at 24). Therefore, the Company stated

[187] In estimating solid waste generation, EEC assumed: (1) coal ash content of seven percent; (2) coal sulfur content of 2.4 percent; and (3) 92 percent SO_2 removal (Exh. AG-RE-18, att. iii at 24). EEC noted that the actual amount of solid waste generated would depend upon the ultimate calcium to sulfur ratio that would be utilized to control SO_2 emissions (id.).

that the solid waste would have a positive impact in the coal mining region and would have no impact on Massachusetts landfills (id.).

With respect to the gas-fired alternatives, NGCC and GOCC, the Company stated that facility operation would not generate appreciable amounts of solid waste (id., att. i, Table 6.6, att. iii at 25).

With respect to the CGCC alternative, the Company stated that the coal gasification process would generate 64,100 tpy of solid waste, or slag, essentially equal to the ash content of the coal (id., att. iii at 25).[188] However, EEC asserted that there was no evidence that the slag could be used for mine reclamation or would be a marketable product (EEC Brief at 150). As such, the Company stated that the solid waste impacts of the CGCC alternative would be greater than the solid waste impacts of the proposed project (id.).

The Attorney General argued that the CGCC alternative would be superior to the proposed project with respect to solid waste impacts (Attorney General Brief at 184-186). He argued that the CGCC alternative would produce only 24.7 percent of the total solid waste generated by the proposed project, and, in addition, all solid wastes produced by the CGCC alternative would be marketable products (id.).[189] He noted that slag is usable as a construction material (Exh. HO-AG-67).

With respect to the RO alternative, EEC stated that facility operation also would not generate appreciable amounts of solid waste (Exh. AG-RE-18, att. i, Table 6.6, att. iii at 25). In addition, EEC stated that the PC alternative would generate 220,000 tpy of solid waste from combustion of coal and operation of the flue gas desulfurization system (id.).

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188 Dr. Breton indicated that the gasification process would cause the coal ash to become molten and then solidify to form slag, a nontoxic and nonleachable glassy substance (Exh. AG-201, at 12).

189 Dr. Breton stated that, in addition to slag, sulfur would be produced by the gasification process (Exhs. AG-210, at 6, 12; HO-AG-41). He stated that the gasification process would remove more than 99 percent of the coal sulfur content and that all sulfur produced at the LGTI facility has been sold (Exhs. AG-201, at 6; HO-AG-42).

However, EEC stated that all such solid waste also would be returned to the coal production area to back-fill coal mines (id., att. iii at 25).

With respect to the MCC alternative, NO-COAL stated that no solid wastes would be generated because the fuel is ash free and no chemicals would be required for air pollution control (Exh. NC-40 at A-7).

ii. Analysis

In comparing the solid waste impacts of the proposed project with the two gas-fired alternatives, NGCC and GOCC, the record demonstrates that the proposed project would generate significant amounts of solid waste -- approximately 260,000 tpy -- while the gas-fired alternatives would not generate any appreciable amount. The record further demonstrates that, although the Company plans to transport the solid waste to the coal production area for potential reuse as back-fill for coal mines, the Company does not have a specific plan or contract in place.

The Siting Board disagrees with the Company's conclusion that significant differences in the amount of solid waste proposed by various technology alternatives is not a measure of solid waste impacts. First, export of significant quantities of solid waste from Massachusetts to another state does not eliminate the impact of solid waste disposal. Second, in the absence of contracts for the transport and use of the solid waste that would be generated by the proposed project, there is no certainty that the waste will be exported and will actually be reused.

Accordingly, based on the foregoing, the Siting Board finds that the NGCC and GOCC alternatives would be preferable to the proposed project with respect to solid waste impacts. In making this finding, the Siting Board recognizes that although a significant amount of solid waste would be generated by the proposed project, the solid waste impacts of the proposed project would be minimal if the solid waste is reused in the manner suggested by the Company to provide environmental benefits to the coal mining region.[190]

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[190] In the EEC Decision, the Siting Council required the Company to submit either (1) a signed agreement for the removal of ash, which includes provisions to ensure safe and (continued...)

In comparing the solid waste impacts of the proposed CFB project and the CGCC alternative, the record demonstrates that the CGCC alternative would generate approximately 25 percent of the solid waste generated by the proposed project. The Siting Board recognizes that the solid waste of both technologies has potential for acceptable reuse that if the waste of both technologies were used in such fashion, impacts of both would be minimal. Nevertheless, the difference in solid waste generation of the two technologies is significant, and as such, for the purposes of this review, impacts of disposal of the solid waste generated by the proposed project would be greater than impacts of the CGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the CGCC alternative would be preferable to the proposed project with respect to solid waste impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that the RO alternative also would not generate solid wastes. Accordingly, based on the foregoing, the Siting Board finds that the RO alternative would be preferable to the proposed project with respect to solid waste impacts.

In comparing the PC alternative to the proposed project, the record demonstrates that both technologies would generate comparable amounts of solid waste and that the solid waste of the PC alternative also has the potential to be transported to coal mines for reuse as backfill. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable the PC alternative with respect to solid waste impacts.

Finally, in comparing the MCC alternative to the proposed project, the record demonstrates that the MCC alternative also would not generate solid wastes. Accordingly, based on the foregoing, the Siting Board finds that the MCC alternative would be preferable to the proposed project with respect to solid waste impacts.

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[190](...continued)
environmentally acceptable removal thereof, or (2) the signed coal supply contract, which includes specific provisions to ensure safe and environmentally acceptable removal of the ash (22 DOMSC at 305).

f. Land Use

i. Description

EEC stated that the proposed site is located within the GNB Industrial Park (Exh. AG-RE-18, att. iii at 8). EEC also stated that the site abuts the Acushnet Cedar Swamp State Reservation ("Cedar Swamp")[191] along its southern and western boundaries (Exh. HO-12A at 3-7). Approximately one-third of the proposed site is covered by forested wetlands that are hydrologically connected to the Cedar Swamp (Exh. HO-2A at 4-25).

Based on space required for power generation facilities, air pollution control devices, raw material storage and handling areas, fuel storage,[192] transportation facilities and temporary ash storage, the Company estimated that acreage requirements of the proposed project and the technology alternatives would vary from 33 to 53 acres (Exh. AG-RE-18, att. iii at 9). EEC stated that the proposed site, over 250 acres in size, would accommodate any of the alternatives and thus, differences in land area requirements of the alternatives would be insignificant (id., att. iii at 8-11). However, in considering the compatibility of each technology alternative to the existing land use and resources at the proposed site, the Company asserted that the land use impacts of the proposed project and the NGCC, GOCC, RO and PC alternatives would be comparable but that the land use impacts of the CGCC facility would be greater than the other alternatives (EEC Brief at 124-125).

EEC stated that the proposed project, including the rail spur, would require a total of 50 acres (Exh. AG-RE-18, att. iii at 9-10). EEC stated that the design of the proposed project would ensure compatibility with surrounding land uses, including minimal impact to on-site wetlands, protection of groundwater hydrology, management of stormwater to

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191 The Cedar Swamp was designated as a National Natural Landmark in 1972 (Exh. DEM-1).

192 EEC indicated that the proposed project will have 15 days of coal storage and, therefore, EEC evaluated fuel storage requirements of technology alternatives on this basis (Exh. AG-RE-18, att. iii at 7).

maintain pre-development conditions,[193] and maintenance of a buffer between site development and off-site resources (id.; Tr. 22, at 126-129, 136-139). The Company added that the mature tree cover on the site provides a buffer which would reduce facility visibility beyond the site boundary (Tr. 22, at 128).

With respect to the NGCC alternative, EEC stated that land requirements would include 8.3 acres for the active facility site and approximately 25 acres for a three-mile pipeline ROW, 70 feet in width, a total of 33.3 acres (Exh. AG-RE-18, att. iii at 10). EEC stated that, although active site requirements of the NGCC alternative would allow for a greater buffer between site development and off-site resources, the impact of land requirements to on-site resources would be comparable for the proposed project and NGCC alternative (Tr. 22, at 126-128). In addition, the Company indicated that 36.1 acres would be required for the GOCC alternative -- 11.1 acres for power generation, fuel storage and rail spur and 25 acres for a pipeline to the site (Exh. AG-RE-18, att. iii at 10-11).

The Attorney General argued the NGCC alternative would be preferable to the proposed project with respect to land use impacts because land requirements would be substantially less (Attorney General Brief at 146).[194]

EEC stated that the CGCC alternative, including a rail spur and air separation unit, would require 52 acres to 54 acres (Exh. AG-RE-18, att. i, Table 6.2; Tr. 22, at 36, 129).[195] However, the Company asserted that operation of the CGCC alternative would potentially impact existing land resources (EEC Brief at 125). EEC explained that due to the size of the CGCC alternative and spacial relationship of facility components, facility

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193 The Company indicated that its stormwater management plan would maintain the pre-development hydrologic characteristics of the facility site, including drainage volumes, flow rates and water quality (Exhs. EEC-2, at 3-4; HO-E-12B, app. E).

194 In addition, the Attorney General argued that a pipeline to the site could potentially follow an existing utility ROW for the entire distance to the site and, as such, new land requirements for the NGCC alternative would be limited to 8.3 acres (Attorney General Brief at 146-147).

195 The Company' witness, Mr. Harkness, indicated that acreage requirements were based on EPRI data (Exh. AG-RR-43).

configuration within the proposed site would potentially impact wetlands and buffer areas (Tr. 22, at 35-36, 136).

The Attorney General argued that the CGCC alternative would be preferable to the proposed project with respect to land use impacts (Attorney General Brief at 182-184). The Attorney General argued that EEC overstated land requirements of the CGCC alternative (id. at 182-183). Dr. Breton estimated that a CGCC facility, comparable in size to the proposed project, would require approximately 20 acres to 40 acres, approximately 20 acres for the gasification, power generation and air separation facilities, 10 acres for the coal handling and storage, and depending on the nature of the site, additional land area for a rail spur (Exh. AG-201, at 11; Tr. JH2, at 44-46).[196] In addition, the Attorney General argued that the layout of the CGCC alternative would be flexible (Attorney General Brief at 183). Dr. Breton stated that the components can be separated and that a CGCC facility could be positioned to easily fit within the confines of the 50-acre active site of the proposed project (Tr. 30, at 48-50).

Finally, EEC stated that the PC alternative would require 53 aces and that the RO alternative would require 48 acres (id.).

In estimating acreage requirements for the MCC alternative, NO-COAL indicated that in addition to the acreage required for a NGCC facility, land requirements would include 1.4 acres for fuel storage and additional land for a ROW for a ten-mile long pipeline (Exh. NC-40, at A-7).

ii. Analysis

In comparing the land use impacts of the proposed CFB project and the NGCC alternative, the record demonstrates that the NGCC alternative would require a total of 16.7 acres less than the proposed project -- 41.7 acres less for the active facility site but 25 acres more for pipeline facilities. The record further demonstrates that the proposed site has sufficient acreage to accommodate the proposed project and that, in addition, the proposed

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[196] Dr. Breton indicated that the gasification and power generation components of the Wabash facility would occupy approximately 20 acres (Tr. JH9, at 28).

project has been designed to minimize impacts to on-site and surrounding resources. However, considering the resources abutting the site, a federally recognized cedar swamp reservation, as well as the resources within the site, forested wetlands hydrologically connected to the cedar swamp, the 41.7 acre difference between the active site land requirements of the two technologies is significant. The decreased land requirements of the NGCC alternative would allow for substantially greater buffer areas between the aforementioned resources and active site area. With respect to the 25 acres required for pipeline construction, the Siting Board recognizes that such construction could impact environmentally sensitive resources. However, such impacts could be minimized by choice of route, construction techniques and pipeline alignment (see Section II.B.4.a., above). Accordingly, based on the foregoing, the Siting Board finds that the NGCC alternative would be preferable to the proposed project with respect to land use impacts.

In comparing the GOCC alternative to the proposed project, the record demonstrates that differences in land requirements would be significant in that the GOCC alternative would require a total of 14 acres less than the proposed project -- 38.9 acres less for the active facility site but 25 acres more for pipeline facilities. Thus, the advantages of the GOCC alternative would be comparable to the advantages of the NGCC alternative. Accordingly, based on the foregoing, the Siting Board finds that the GOCC alternative would be preferable to the proposed project with respect to land use impacts.

With respect to the CGCC alternative, the record demonstrates that land requirements would vary from 40 to 54 acres. In addition, given that the components of the CGCC alternative could be separated, it is reasonable to assume that there would be sufficient flexibility in the layout of the CGCC alternative such that facility components could fit within the confines of the active-site area of the proposed project, thereby minimizing impacts to on-site and abutting resources. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the CGCC alternative with respect to land use impacts.

In comparing the RO alternative to the proposed project, the record demonstrates that land use requirements would be similar in that the proposed project would require only two more acres. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the RO alternative with respect to land use impacts.

In comparing the PC alternative to the proposed project, the record demonstrates that land use requirements would be similar in that the PC alternative would require only three more acres. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be comparable to the PC alternative with respect to land use impacts.

Finally, with respect to the MCC alternative, the record demonstrates that the land requirements would be greater than the requirements of the NGCC alternative due to (1) a fuel storage area, and (2) approximately seven additional miles of pipeline. Although fuel storage can be accommodated on-site, land use impacts of potential fuel storage requirements in the New Bedford harbor vicinity have not been investigated. In addition, the acreage requirements of a pipeline to the site have not been estimated. Accordingly, based on the foregoing, the Siting Board can make no finding regarding the relative land use impacts of the proposed project and the MCC alternative.

g. Findings and Conclusions on Environmental Impacts

With respect to fuel transportation impacts, the Siting Board has found that (1) the CGCC alternative would be minimally preferable to the proposed project (p. 75), (2) the PC alternative would be comparable to the proposed project (p. 75), and (3) the proposed project would be preferable to the GOCC, RO and MCC alternatives (pp. 75-77). In addition, the Siting Board could make no finding regarding the relative transportation impacts of the proposed project and the NGCC alternative (p. 76).

With respect to air quality impacts, the Siting Board has found that: (1) the NGCC, GOCC and MCC alternatives would be preferable to the proposed project (pp. 92-94); (2) the proposed project would be preferable to the CGCC and RO alternatives (pp. 93-94); and (3) the proposed project would be comparable to the PC alternative (p. 94). In addition, the Siting Board has found that the Company's dispatch analysis establishes that the proposed project likely would provide short-term air quality benefits for Massachusetts and New England, but has not established that the proposed project would provide significant long-term air quality benefits, based on the modeled dispatch effects (p. 101).

With respect to water supply impacts, the Siting Board has found that (1) the proposed project would be preferable to the NGCC, GOCC and CGCC and PC alternatives (pp. 108-110) and (2) the proposed project would be comparable to the RO alternative (p. 110). In addition, the Siting Board could make no finding regarding the relative water supply impacts of the proposed project and the MCC alternative (p. 110).

With respect to wastewater impacts, the Siting Board has found that the proposed project would be comparable to the NGCC, GOCC, CGCC, RO, PC, and MCC alternatives (pp. 111-112).

With respect to noise impacts, the Siting Board has found that: (1) the proposed project would be comparable to the NGCC, GOCC, and PC alternatives (pp. 116, 117); (2) the proposed project would be preferable to the CGCC alternative (p. 117); and (3) the RO facility would be slightly preferable to the proposed project (p. 117). In addition the Siting Board could make no finding regarding the relative noise impacts of the proposed project and the MCC alternative (p. 118).

With respect to solid waste impacts, the Siting Board has found that (1) the NGCC, GOCC, CGCC, RO, and MCC alternatives would be preferable to the proposed project (pp. 120-121), and (2) the proposed project would be comparable to the PC alternative (p. 121).

With respect to land use impacts, the Siting Board has found that (1) the NGCC and GOCC alternative would be preferable to the proposed project (p. 125), and (2) the proposed project would be comparable to the CGCC, RO, and PC alternatives (pp. 125-126). In addition the Siting Board could make no finding regarding the relative land use impacts of the proposed project and the MCC alternative (p. 126).

In comparing the overall environmental impacts of the proposed project and the NGCC alternative, the Siting Board has found that the NGCC alternative would be preferable to the proposed project with respect to air quality, solid waste and land use impacts, that the proposed project would be preferable with respect to water supply impacts and that the proposed CFB project would be comparable to the NGCC alternative with respect to wastewater and noise impacts. In addition, the Siting Board could make no finding regarding the relative fuel transportation impacts of the proposed project and the NGCC alternative.

The Siting Board notes that, although the NGCC alternative was found to be preferable with respect to solid waste impacts due to the significant amount of solid waste that would be generated by the proposed project, there is potential for the solid waste of the proposed project to be utilized such that it would have a positive impact on coal mining regions. As such, the advantage of the NGCC alternative is limited with respect to solid waste impacts.

The Siting Board also notes that, although the NGCC alternative was found to be preferable with respect to land use impacts based on the potential for substantially greater buffer areas between the active site area and resource areas and an overall reduction in land area requirements of 16.7 acres, the proposed project has been designed to minimize impacts to on-site and surrounding resources. In addition, a overall reduction of 16.7 acres, although preferable, is not of major significance at this site. As such, the advantage of the NGCC alternative is also limited with respect to land use impacts.

In addition, the Siting Board notes that the proposed project was found to be preferable with respect to water supply impacts. However, given the availability of dry NOx control technology that would significantly reduce the water requirements of the NGCC alternative and the potential future use of such technology in NGCC facilities, the Siting Board further notes that this superiority could be reversed in the future. As such, the advantage of the proposed project is limited with respect to water supply impacts.

However, the Siting Board notes that the NGCC alternative would have significant advantages with respect to air quality. Except for emissions of VOC, emissions of criteria pollutants and CO_2 would be far less for the NGCC alternative and, with a potential improvement in heat rate, the emissions advantage of the NGCC alternative would further increase.

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

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

The Siting Board notes that the advantage of the proposed project with respect to fuel transportation was based on the potential for accidental oil spills in transporting oil to the GOCC alternative. Given that oil would be used for a maximum of two months per year, the advantage of the proposed project with respect to fuel transportation impacts is limited. With respect to water supply impacts, the Siting Board also notes that, for the reasons stated above for the NGCC alternative, the advantage of the proposed project would be limited. With respect to solid waste and land use impacts, the Siting Board notes that, for the reasons stated above for the NGCC alternative, the advantage of the GOCC alternative would be limited. In addition, although the emissions of the GOCC alternative would be slightly higher than the NGCC alternative, for the reasons stated above, the Siting Board notes that the advantage of the GOCC alternative also would be significant with respect to air quality.

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

In comparing the overall environmental impacts of the proposed project and the CGCC alternative, the Siting Board has found that the CGCC alternative would be minimally preferable with respect to fuel transportation impacts, that the proposed project would be preferable with respect to air quality, noise, and water supply impacts, and that the proposed project and CGCC alternative would be comparable with respect to land use and wastewater impacts.

In considering the overall environmental impacts of the CGCC alternative relative to the overall environmental impacts of the proposed project, the Siting Board notes that although less solid waste would be produced by the CGCC alternative, the advantage of the CGCC alternative with respect to solid waste impacts is limited given the potential for the solid waste of the proposed project to be utilized such that it would have a positive impact on coal mining regions.

However, the Siting Board further notes that, given the potential for emissions of benzene and H_2S from the CGCC alternative to exceed Massachusetts established standards under worst case conditions, the proposed project would have a significant advantage with respect to air quality. In addition, although the CGCC alternative could have greater noise impacts due to the characteristics of noise sources, the record does not demonstrate that any advantage of the proposed project with respect to noise would be significant. Finally, with respect to water use impacts, the Siting Board also notes that, for the reasons stated above for the NGCC alternative, the advantage of the proposed project would be limited.

Thus, the CGCC alternative would be minimally preferable with respect to fuel transportation impacts, and would have a limited advantage with respect to solid waste impacts. The proposed project would have a limited advantage with respect to water supply impacts but the proposed project would have a significant advantage with respect to air quality and likely would have an advantage with respect to noise impacts. Accordingly, on balance, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the PC alternative, the Siting Board has found that the proposed project would be preferable with respect to water supply impacts and that the proposed project and the PC alternative would be comparable with respect to fuel transportation, air quality, wastewater, solid waste, noise, and land use impacts. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the PC alternative with respect to environmental impacts.

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

In considering the overall environmental impacts of the RO alternative relative to the overall environmental impacts of the proposed project, the Siting Board notes that the proposed CFB project would have a significant advantage with respect to fuel transportation impacts given that the potential for accidental oil spills on a year-round basis. The Siting Board also notes that although less solid waste would be produced by the RO alternative, the advantage of the RO alternative with respect to solid waste impacts is limited given the potential for the solid waste of the proposed project to be utilized such that it would have a positive impact on coal mining regions.

Thus, the proposed project would have a significant advantage with respect to fuel transportation impacts, would be slightly preferable with respect to air quality impacts while the RO alternative would be slightly preferable with respect to noise impacts and would have a limited advantage with respect to solid waste impacts. Accordingly, on balance, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to environmental impacts.

In comparing the overall environmental impacts of the proposed project and the MCC alternative the Siting Board has found that the proposed project would be preferable with respect to fuel transportation impacts, that the MCC alternative would be preferable with respect to air quality impacts and solid waste impacts and that the proposed project and MCC alternative would be comparable with respect to wastewater impacts. In addition the Siting Board made no finding regarding the relative water supply, noise and land use impacts of the proposed project and the MCC alternative.

In considering the overall impacts of the MCC alternative relative to the overall impacts of the proposed project, the Siting Board notes that for many categories of impacts, information regarding the MCC alternative was insufficient for the Siting Board to determine which of the two technologies would be preferable. Although the Siting Board did find that the MCC alternative would be preferable with respect to air quality and that the proposed project would be preferable with respect to fuel transportation impacts,[197] limited information was provided regarding the impacts of the MCC alternative and further, such information was not substantiated by data from operational or proposed facilities or by data compiled by an industry-wide source such as EPRI. Thus, the Siting Board gives limited consideration to these findings.

Accordingly, based on the foregoing, the Siting Board an make no finding regarding the relative environmental impacts of the proposed project and the MCC alternative.

5. Cost

In this section, the Siting Board evaluates the proposed project in terms of whether it minimizes cost by determining if the project is superior to a reasonable range of practical alternatives in terms of cost.[198]

a. Description

The Company compared the power costs of the proposed project with the NGCC, GOCC, CGCC, RO and PC alternatives by using a total revenue requirements methodology (Exh. HO-AER-9(a)(A)). Essentially, EEC projected the total revenue requirements for each option for each year over a 20-year period with an assumed in-service date of March, 1997, by discounting revenue requirements into net present value terms and then levelizing these amounts to derive a cost of power in dollars per megawatt hour ("$/MWh") (id.).[199] The

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197 Although the Siting Board also found that the MCC alternative would be preferable to the proposed project with respect to solid waste impacts, the advantage of the MCC alternative is limited given the potential for the solid waste of the proposed project to be utilized such that it would have a positive impact on coal mining regions.

198 The Siting Board also requires proponents to establish that the project offers power at a cost below purchasing utilities' avoided costs. The Siting Council considered whether the proposed project offered power at a cost below purchasing utilities' avoided costs in the EEC Decision, 22 DOMSC at 297-299. The Siting Council noted that EEC had demonstrated that it would be able to offer its power at or below the avoided costs of several Massachusetts utilities. Id. at 299.

199 In projecting total revenue requirements for each alternative, the Company utilized consistent assumptions with respect to cost of debt, cost of capital, tax rate, and depreciation (Exh. HO-AER-9(a)(A)).

Company indicated that the primary cost factors were: (1) capital costs; (2) operation and maintenance costs ("O&M"); (3) fuel costs; (4) interest rates;[200] (5) availability factor;[201] and (6) heat rate (Exh. HO-AER-9(a)(A)).

With respect to capital, O&M, and fuel costs, the Company computed a base cost and then escalated base costs in accordance with respective escalation rates provided in the NEPOOL 1991 Generation Task Force Assumptions ("GTF") (Exh. HO-AER-9(a)(A)). The Company also provided higher and lower fuel cost scenarios, assuming annual escalation factors for each fuel at ten percent higher and lower than the GTF in every year beyond 1992 (id.). The Company stated that its analysis demonstrated that the proposed project would be preferable to the CGCC, NGCC, GOCC, RO and PC technology alternatives, with respect to cost (id.).

For the proposed project, EEC calculated a levelized cost based on project-specific factors for heat rate, availability factor and 1997 capital costs (Exhs. HO-AER-9(a)(A); HO-AER-22). See Table 4. With respect to fuel costs, the Company indicated that although a coal contract has not been finalized, the Company assumed: (1) use of coal with 2.4 percent sulfur content;[202] (2) an initial 1992 fuel price of $42 per ton;[203] and (3) GTF escalation factors for three percent sulfur coal (Exhs. HO-AER-9(a)(A); HO-AER-25;

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200 For the proposed project and all technology alternatives, EEC assumed a debt term of 20 years and an interest rate of 11 percent (Exh. HO-AER-25).

201 The Company explained that availability factor represents the typical operating hours available for power generation on an annual basis (Tr. 23, at 94-95).

202 EEC indicated that use of 2.4 percent sulfur coal would be consistent with the Siting Board directives in the EEC Compliance Decision with respect to SO_2 emissions (Exh. HO-AER-25).

203 EEC indicated that it had identified a source of 2.4 percent sulfur coal with a high heat value and that preliminary discussions with coal suppliers confirmed that $42 per ton would be an achievable price (Exh. HO-AER-34; Tr. 22, at 107). EEC noted that the cost of fuel transportation was included in the coal price and the cost of transporting solid waste back to the mine was included in O&M costs (Exhs. HO-AER-9(a)(A); AG-RE-37).

HO-AER-33).[204] EEC noted that, although the GTF predicts annual coal price escalation rates in the range of 4.5 percent to 5 percent, actual coal price escalation likely would be less than this amount (Exh. HO-AER-34).[205]

In calculating the levelized cost for the NGCC, GOCC, CGCC, RO and PC technology alternatives the Company utilized (1) 1989 TAG data to determine availability factors, heat rate, base capital costs[206] and base O&M costs, and (2) various fuel price forecasts[207] to determine base fuel costs including: (a) New England-specific data, reported in a United States Department of Energy ("DOE") publication ("DOE forecast");[208] (b) the 1991 GTF fuel prices ("GTF forecast");[209] (c) the January through October 1992 average fuel price for a specific NEPOOL unit with comparable fuel characteristics ("NEPEX

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[204] EEC noted that even if the GTF escalation factors associated with 1.8 percent sulfur coal had been utilized, the resulting price, 20 years after the 1997 assumed starting date, would have been only 0.08 percent higher (Exh. HO-AER-33).

[205] The Company stated that productivity improvements have kept the delivered cost of coal below the inflation rate for the past 15 years and that, therefore, coal price escalation likely would be equal to or less than the rate of inflation (Exh. HO-AER-34).

[206] EEC noted that the accuracy range for TAG cost estimates for a technology rated as mature, i.e., NGCC or GOCC, would be within ten percent while the accuracy range for a technology rated as demonstration, i.e., CGCC, would be within 15 percent (Exh. HO-AER-26).

[207] The Company indicated that all fuel price forecasts included fuel transportation (Exhs. HO-AER-9(a)(A); HO-AER-28; HO-RR-116; HO-RR-128).

[208] For the DOE forecast, EEC utilized the January through May 1992 weighted average monthly cost of fuel for all New England power plants to compute 1992 base fuel cost (Exhs. HO-AER-9(a)(A); HO-AER-28).

[209] The Company indicated that the 1992 gas prices, projected by escalation of the 1991 GTF prices by the GTF escalation factor were significantly less than actual 1992 gas prices (Exh. HO-RR-116). Therefore, the Company escalated the 1991 GTF base price by actual market data for 1992 (id.).

forecast");[210] and (d) for the two natural-gas fired alternatives, NGCC and GOCC, a fourth fuel price forecast based on projected 1992 through 1994 spot market gas prices quoted in "Natural Gas Week" ("NGW forecast") (Exhs. HO-AER-9(a)(A); HO-AER-28; HO-RR-116; HO-RR-128).[211,212]

In order to provide cost estimates consistent with the cost estimate of the proposed project, the Company adjusted certain TAG-specified data (Exh. HO-AER-9(a)(A)). Specifically, the Company adjusted the TAG-specified heat rates to reflect the steam export and cooling technology of the proposed project,[213] and the TAG-specified capital and O&M base costs to reflect the northeast location of the proposed project and additional environmental controls that would be required to meet current BACT standards (id.).[214] However, the Company asserted that use of industry data likely would understate costs of the

210 For the NGCC alternative, the fuel price for a comparable facility was available only for the months of May through October (Exh HO-AER-28).

211 EEC noted that projections of future spot market prices by AGT were seven percent higher than NGW projections (Exh. HO-RR-128).

212 EEC indicated that base fuel prices were escalated by GTF escalation factors for all alternative fuel price forecasts (Exhs. HO-RR-116; HO-RR-128; HO-AER-28). EEC noted that DOE projections for the price of natural gas consumed by electric utilities in the northeast forecast a more rapid rise in gas prices than the GTF escalation factors used in the analysis (Exh. HO-RR-127).

213 The Company indicated that TAG-specified heat rates were increased by (1) two percent to account for air-cooled condensers, and (2) 965 Btu/kWh to reflect steam export (Exh. HO-AER-9(a)(A)).

214 EEC noted that, when calculating levelized costs under the DOE and NEPEX forecasts, the TAG-specified capital costs were not adjusted to account for air-cooled condensers which would increase capital costs of the technology alternatives by approximately ten to 15 million dollars (Exh. HO-AER-26). However, EEC indicated that, when calculating levelized costs under the GTF and NGW forecasts, capital costs were increased by $50/kW to reflect the cost of the air-cooled condensers (Exhs. HO-RR-116; HO-RR-128).

alternatives because it fails to reflect project-specific and site-specific costs that were included in the cost estimate for the proposed project (EEC Brief at 96).[215]

For the NGCC alternative, EEC calculated levelized costs based on the four fuel forecasts (Exhs. HO-AER-9(a)(A); HO-AER-28; HO-RR-116; HO-RR-128). See Table 4. In calculating capital costs, the Company indicated that (1) TAG-specified costs were increased to reflect installation of SCR, and (2) TAG data for conventional rather than advanced combined-cycle technology was utilized (id.; Exh. HO-AER-19; Tr. 24, at 86-88).[216]

EEC also provided the heat rates for four newly constructed and/or proposed gas-fired facilities in Massachusetts (Exh. HO-AER-22; HO-RR-110, sup.) The Company indicated that, after adjustment for consistency with the proposed project, said heat rates would range from 7,859 Btu/kWh to 9,920 Btu/kWh (id.). Based on the DOE forecast and the assumed heat rate of 7,859 Btu/kWh, the Company indicated that the levelized cost of the NGCC alternative would decrease by approximately 6.7 percent (Exhs. HO-AER-9(a)(A), Table 5.3; HO-RR-124). See Table 4.

The Attorney General argued that application of the externality values to the pollutant values for the proposed project and the NGCC alternative demonstrate that the proposed project would be substantially more expensive than the NGCC alternative (Attorney General

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215 The Company noted that site-specific and project-specific costs that were included in the capital cost estimate for the proposed project include costs of transportation infrastructure, and environmental mitigation in areas such as noise control and wetlands protection (Exhs. HO-AER-19; HO-AER-26). As noted above in Section II.B.4.a., above, the Company provided an AGT analysis of pipeline facilities necessary to transport natural gas to the site on a firm basis which indicated that the cost of pipeline and metering facilities, exclusive of mainline construction, would be 6.8 million to 7 million dollars (1993 dollars) (Exh. AG-RE-39, att. 1). However, the Company indicated that for the NGCC and GOCC alternatives, the cost of gas pipeline facilities was included in calculating costs under the GTF and NGW forecasts (Exhs. HO-RR-116; HO-RR-128).

216 Mr. La Capra explained that advanced combined-cycle technology refers to greater efficiencies in the heat recovery steam boiler but that facilities currently in the planning stages would operate as conventional rather than advanced units (Tr. 24, at 86-88).

Brief at 199-201, Figure 1). In addition, the Attorney General argued that the NGW forecast levelized cost of 99 $/MWh, which was based on the most up-to-date information, included inflated variable costs because an excessive heat rate was assumed (id. at 200-201).

With regard to the GOCC alternative, the Company also calculated levelized costs based on the four fuel forecasts and noted that levelized costs were less than those of the NGCC alternative (Exhs. HO-AER-9(a)(A); HO-AER-28; HO-RR-116; HO-RR-128). See Table 4. EEC asserted that fuel costs are the primary determinant of the total levelized cost for the gas-fired alternatives, and that therefore, the significant cost advantage of an interruptible supply over a firm supply gives the GOCC facility its cost advantage over the NGCC facility (EEC Brief at 90-103). However, the Company stated that the assumed natural gas supply -- 10 months of interruptible supply over a 20-year period -- was not a realistic supply option given that interruptible supplies historically have been available in New England for only eight to nine months (Exh. HO-RR-128). The Company stated that, in addition, an increase in oil firing would not be a realistic assumption because (1) costs would increase, and (2) more than two months of oil firing would not be allowed under environmental permits (id.). The Company asserted that the GOCC alternative could therefore be without a fuel supply for up to two months per year, reducing the availability by 10 percent to 15 percent and resulting in a comparable increase in the levelized cost (EEC Brief at 99).

With respect to the CGCC alternative, EEC calculated levelized costs based on: (1) the TAG-specified availability factor and heat rate; (2) the TAG-specified capital costs increased to reflect use of SCR for NOx control; (3) the DOE, GTF and NEPEX forecasts for 1.8 percent sulfur coal; and (4) the 2.4 percent sulfur coal assumed for the proposed project (Exhs. HO-AER-9(a)(A); HO-RR-116; HO-RR-128; HO-RR-123). Initially, the Company utilized the TAG-specified capital costs for a 200 MW non-integrated facility[217] but, during

[217] Mr. La Capra explained that an integrated unit is essentially one plant where the coal is gasified and moved into the combustion cycle of the power plant while a non-integrated unit has separate coal gasification and power generation units (Tr. 22, at (continued...)

the course of the proceeding, also computed levelized costs based on TAG-specified capital costs for a 200 MW integrated facility and a 400 MW integrated facility (Exhs. HO-RR-121; HO-AER-17; AG-RR-61; Tr. 24, at 95).[218] See Table 4.

With regard to the availability factor of the CGCC alternative, the Company indicated that the TAG-specified availability factor of 85.5 percent assumes mature technology status for the CGCC alternative (Tr. 23, at 110; Tr. 24, at 95-96).[219] The Company explained that maturity of a technology addresses the predictability of outages and is established over a period of time, as a technology develops an operating history (Tr. 23, at 94-95). Although the Company utilized the TAG-specified availability factor in its analysis, the Company stated that the CGCC technology has not reached the level of a mature technology but instead, classified the CGCC technology as a yet unproven technology (Tr. 24, at 95; Tr. 23, at 134).[220] The Company stated that, historically, the availability of the CGCC technology

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[217](...continued)
162). He stated that an integrated unit would be more consistent with the lower availability rates demonstrated by pilot projects, while a non-integrated unit could more easily utilize back-up fuels to attain the assumed availability rate of 85 percent (Tr. 24, at 94).

[218] In response to a request by the Attorney General, EEC noted that without the capital and operating costs for SCR, the levelized cost of the CGCC alternative would be 92 $/kWh, based on the DOE forecast and TAG-specified data for a non-integrated 200 MW facility (Exh. AG-RR-56). However, Dr. Breton indicated that in order to control NOx emissions to 9 ppm, SCR would be required (Tr. JH3, at 60-61).

[219] Mr. La Capra stated that the TAG-specified availability factor of 85.5 percent is not based on actual field engineering or operating data, but rather, it is a rate that the technology is expected to approach as the technology matures (Tr. 24, at 95-96). He further stated that the TAG report would specify an optimistic heat rate so that emerging technologies would not be discouraged (id. at 134).

[220] EEC stated that there are only a small number of CGCC facilities operating in the United States and few under development, providing minimal operating history or permit data (Exh. EEC-AG-20; Tr. 22, at 95-96). EEC indicated that most CGCC facilities have started out as demonstration projects with external funding (Tr. 22, at 96).

(continued...)

has been low in relation to the expected availability factor of a mature technology, noting that the average annual availability factor of the LGTI facility is approximately 62 percent (Tr. 22, at 97). The Company asserted that the low availability record of the CGCC technology would impact its commercial viability given that a decrease in availability from 85 percent to 60 percent would increase levelized costs by approximately 50 percent (Exh. HO-RR-61; EEC Brief at 105-109).[221]

The Attorney General argued that the CGCC alternative would be superior to the proposed project because the Company overstated the capital, O&M and fuel costs as well as the heat rate for the CGCC alternative (Attorney General Brief at 202-208). Dr. Breton indicated that the capital cost of a CGCC facility would be approximately 76 percent of the Company's estimated capital cost for the CGCC alternative (Exhs. AG-201, at 11, HO-RR-146, HO-AER-9(a)(A)).[222] Dr. Breton noted that his estimate of capital costs was consistent with the estimated capital costs of the Wabash facility (Tr. JH3, at 95-96). However, Dr. Breton also noted that the Wabash facility would make use of a number of

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[220](...continued)

In contrast, EEC indicated that the CFB technology is a well-defined, advanced technology given that operational and permitted data is available for a number of CFB facilities that have come on line in recent years or are currently under development (Tr. 22, at 94-95; Tr. 23, at 133-134).

The Company asserted that the Attorney General's own witness acknowledged that the CGCC technology was five to ten years behind the CFB technology in terms of maturity (EEC Brief at 106, citing, Tr. JH3, at 112-113).

[221] EEC noted that Dr. Breton acknowledged that "when the 85 percent is reached by an operating plant, you can say that gasification has arrived in terms of a strong competitor with any other coal-based technology" (EEC Brief at 108, citing, Tr. JH2, at 146-147).

[222] Based on the EPRI study, Dr. Breton originally estimated that capital cost of a CGCC facility would be $620 million, or $2,067/kW in 1997 dollars (Exh. AG-201, at 11). Then, Dr. Breton recalculated that capital costs would be $616 million, based on his revised heat rate and facility parameters consistent with the proposed project (Exh. HO-RR-146).

existing facilities including the steam turbine and coal unloading facilities, and in addition, the land for the facility was donated (Tr. JH9, at 40).

With regard to heat rate, Dr. Breton stated that the heat rate of a CGCC facility would be lower than the heat rate assumed by the Company, decreasing annual fuel requirements and associated costs (Exhs. AG-201, at 10; AG-205, rev.; Tr. 30, at 12-14).[223] See Section II.B.4.b., above. In addition, the Attorney General noted that all revisions to the Company's original levelized cost estimates for the CGCC alternative, i.e., use of 2.4 percent sulfur coal rather than 1.8 percent sulfur coal, assumption of an integrated rather than a non-integrated unit, scaling from 400 MW facility rather than a 200 MW facility, have resulted in lower cost estimates (Attorney General Brief at 203-206). See Table 4.

The Attorney General also argued that the CGCC technology would achieve an 85 percent availability rating by the time the proposed project is scheduled to go on line (Attorney General Reply Brief at 11). In explaining the historical availability of the LGTI facility in the 60 percent range, Dr. Breton stated that the facility is a demonstration plant, that modifications and improvements to plant systems have continued since initial operation in 1987, and that significant improvements have been made to the processes that have contributed most to plant outages (Exhs. AG-210, at 7; JH-RR-2; Tr. JH2, at 83-87,

223 The Attorney General argued that, assuming use of 2.4 percent sulfur coal, fuel costs for a CGCC facility would be 13.9 percent less than fuel costs for the proposed project (Attorney General Brief at 206).

131-136, 142-144).[224] Dr. Breton indicated that, in order to achieve an overall plant availability of 85 percent, the availability of the gasification process would have to reach 88 percent, but that such availability would be achievable in the mid- to late-1990's (Tr. JH2, at 140-141).[225]

Finally, the Attorney General noted that the TAG report specifies a higher availability factor for the CGCC technology than for the CFB technology (Attorney General Brief at 166-167, citing, Exh. HO-AER-17, att. at 7-27). The Attorney General further noted that the most significant economic constraint to the development of CGCC facilities is the low price and abundant supply of natural gas, which is the direct competitor of syngas (Tr. JH3, at 117-118).

With regard to the PC alternative, the Company provided levelized costs based on the DOE, GTF and NEPEX fuel price forecasts for 1.8 percent sulfur coal (Exhs. HO-AER-9(a)(A); HO-RR-116; HO-RR-128). See Table 4. In calculating capital costs, EEC stated that TAG-specified costs were increased to reflect installation of a dry scrubber and SNCR (Exh. HO-AER-9(a)(A)).

Finally, with respect to the RO alternative, the Company provided levelized costs based on DOE, GTF and NEPEX fuel price forecasts (Exhs. HO-AER-9(a)(A); HO-RR-116; HO-RR-128). See Table 4. In calculating capital costs, the Company stated that TAG-specified costs were increased to reflect the addition of SNCR (Exh. HO-AER-9(a)(A)).

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224 Dr. Breton stated that the overall availability of the coal gasification portion of the LGTI facility was 62.83 percent for 1992, and that quarterly availabilities were as follows: (1) 57.39 percent, first quarter; (2) 53.89 percent, second quarter; (3) 76.41 percent, third quarter; and (4) 63.47 percent, fourth quarter (Exh. JH-RR-2). Dr. Breton explained that availabilities in the first and second quarters were impacted by a planned replacement of the syngas cooler and problems associated with the wet particulate removal system (id.). Dr. Breton noted that the processes that have contributed most to nonavailability of the LGTI facility include: (1) the burner on the gasifier; (2) the heat-recovery area; (3) the wet particulate removal system; and (4) coal testing (Tr. JH1, at 142, 149).

225 Dr. Breton indicated that the anticipated availability of the Wabash facility was proprietary and confidential (Tr. JH2, at 145-146).

NO-COAL stated that the levelized cost of the MCC alternative would be less than the levelized cost of the proposed project (Exh. HO-NC-37, att. 2). NO-COAL stated that its determination of levelized cost was consistent with the Company's determination of levelized costs for the proposed project and technology alternatives (id.).[226] With respect to specific variables, NO-COAL indicated that: (1) capital and O&M costs were based on costs of the GOCC alternative; (2) fuel escalation factors were based on the GTF escalation for 1.8 percent sulfur coal; (3) base fuel costs were provided by Yankee Energy; and (4) facility heat rate was based on data provided by a combustion turbine manufacturer and adjusted for air-cooled condensers and steam export (id.; Exhs. NC-40 at A-8; HO-NC-36; Tr. 26, at 53-55).[227] With regard to fuel costs, NO-COAL stated that although a fuel escalation factor was included in its analysis, Yankee Energy has indicated that methanol would be provided at a cost of $5/MMBtu, without escalation, for a ten-year period and without significant price modifications after ten years (Exh. HO-NC-37; Tr. 25, at 185-189).[228,229] NO-COAL

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226 In calculating the levelized cost of the MCC alternative, NO-COAL calculated the first year cost based on project-specific data for fuel purchases and fuel costs and GOCC data for other variables (Exh. HO-NC-37, att. 2). NO-COAL then computed the ratio of 20-year levelized cost to first year cost for a CFB facility and utilized that ratio to compute the 20-year levelized cost from the first year cost for the MCC alternative (id.).

227 Mr. Ladino indicated that the heat rate of 8,250 Btu/kWh was based on information regarding combined cycle natural gas-fired combustion turbines provided by a manufacturer (Exh. HO-NC-36; Tr. 26, at 53-54). Mr. Ladino indicated that turbine modifications that would be required to burn methanol would not affect the heat rate (Tr. 26, at 57).

228 NO-COAL indicated that without incorporation of a fuel escalation factor, the MCC levelized cost would decrease to 67.59 $/MWh (Exh. NC-40, at A-8).

229 NO-COAL indicated that a specific feedstock location was not assumed in the methane cost of $5/MMBtu (Exh. HO-NC-40, at A-8; Tr. 25, at 48-49). NO-COAL stated that, although capital costs for extracting methane would vary depending on the nature of the feedstock source, i.e., flared methane or abandoned gas in fields that had to be developed, the feedstock costs are a minor part of producing methanol and would not impact the fuel price (Tr. 25, at 57, 66).

noted that the fuel cost would include delivery to port but would not include unloading or storage or transportation from the port to the site (Tr. 25, at 144, 147, 157, 162). However, NO-COAL stated that because capital and O&M cost estimates include SCR, which would not be required for a MCC facility, SCR costs would account for costs not specified in its analysis including a methanol storage and delivery system and turbine modifications (Exh. HO-NC-36; Tr. 26, at 68-70).

EEC raised concerns regarding NO-COAL's cost analysis (EEC Brief at 87-91). First, the Company asserted that the projected price of methanol was unrealistic and uncertain (id.). The Company asserted that all aspects of the proposal which would determine fuel availability and cost, including the feedstock source, construction of the plantship and method of fuel delivery to the site are uncertain (id. at 88-91). The Company indicated that Yankee Energy does not have an agreement with any potential sources of feedstock and the price of the plantship has not been negotiated (id. at 87- 89, citing, Tr. 25, at 50, 74-78, 80-81). EEC further asserted that a financial analysis prepared by Yankee Energy demonstrates that the price of methanol would be significantly higher than the projected fuel price of $5/MMBtu (id. at 86-88). Third, with regard to storage and transport of the methanol from the harbor to the site, EEC indicated that there is no evidence that: (1) a site sufficient to accommodate methanol storage is available in the vicinity of New Bedford harbor; (2) rail transportation from the harbor to the site would be technically, environmentally or economically feasible; or (3) pipeline transportation would be a feasible option (id at 90, citing, Tr. 25, at 152-155, 164-166).

NO-COAL responded that the economic viability of the MCC alternative is not restricted to a fuel price of $5/MMBtu for ten years (NO-COAL Reply Brief at III-1). NO-COAL indicated that its analysis of 20-year levelized cost includes an escalation factor (id.).

b. Analysis

As a preliminary matter, in comparing the levelized cost of the proposed project to the technology alternatives, the Siting Board recognizes that the capital cost estimates for the technology alternatives likely would be conservative in relation to the capital cost estimates for the proposed project. The capital cost estimates for the proposed project include site-specific and project-specific costs, such as the cost of noise mitigation and wetlands protection, that are not included in the capital cost estimates for the technology alternatives. In addition, given that the costs of a generating facility are likely to be spread over a 30 year or more period and that the capital costs of the proposed project are significantly higher than the capital cost of either gas-fired alternative (see Table 4), the Siting Board recognizes that the use of a 20-year period for calculating levelized cost would increase the levelized cost of the proposed project relative to the levelized cost of the NGCC and GOCC alternatives.[230]

With respect to the proposed project, the record demonstrates that the levelized cost would be 83.09 $/MWh. In comparing the cost of the proposed project to the NGCC alternative, the record demonstrates that, assuming the heat rate for the NGCC alternative provided by the Company, the levelized cost of the NGCC alternative would range from 99.32 $/MWh to 112.20 $/MWh under the various fuel price forecasts. The record further demonstrates that a 16.6 percent reduction in heat rate, based on the heat rate of a currently proposed NGCC facility, would decrease levelized costs by 6.7 percent under the DOE forecast. Assuming the same decrease in levelized costs under all fuel price forecasts, the range of levelized costs of the NGCC alternative would decrease to 92.67 $/MWh to 104.68 $/MWh. Thus, the lowest levelized cost for the NGCC alternative would be 11.5 percent greater than the levelized cost of the proposed project.

In considering fuel costs of the NGCC alternative, the Siting Board recognizes that recently constructed natural-gas fired facilities typically do not have a firm gas supply for 365 days. Instead, a firm supply for ten months with an interruptible gas supply and oil back-up for a short period of time would be more likely. See West Lynn Decision, 22 DOMSC at 73; MASSPOWER Decision, 20 DOMSC at 361-367; Altresco Decision, 17

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230 In comparing the relative costs of the proposed project and technology alternatives, the Siting Board considers the various fuel price forecasts to represent a reasonable range of potential fuel price scenarios, for the purpose of this review. Therefore, the Siting Board does not consider the Company's higher and lower fuel price scenarios which were based on both an increase and decrease of ten percent in the escalation factors for each fuel.

DOMSC at 382-385; NEA Decision, 17 DOMSC at 379-380, 398. The Siting Board recognizes that such a fuel supply would likely reduce levelized costs. However, a firm natural gas supply for 365 days is not an unreasonable assumption, and projects with such arrangements have been proposed and approved. See Enron Decision, 23 DOMSC at 7. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the NGCC alternative with respect to cost.

In comparing the cost of the proposed project with the GOCC alternative, the record demonstrates that, assuming the heat rate for the GOCC alternative provided by the Company, the levelized cost of the GOCC alternative would range from 85.72 $/MWh to 102 $/MWh. However, assuming the same reduction in heat rate and associated decrease in levelized costs as assumed for the NGCC alternative, the levelized cost of the GOCC alternative would range from 79.97 $/kW to 95.75 $/kW. Thus, under one fuel price scenario, the GOCC facility would be less costly than the proposed project.

However, the Siting Board recognizes that the assumed natural gas supply of the GOCC alternative -- 10 months of interruptible gas -- would not be a realistic supply option. A facility that has an assured fuel supply for only two months would not be financeable. The Siting Board notes that, as with the NGCC alternative, a more realistic fuel supply for a GOCC facility would be firm gas for ten months with an interruptible gas supply and oil back-up for a maximum of 35 days. See West Lynn Decision, 22 DOMSC at 73; MASSPOWER Decision, 20 DOMSC at 361-367; NEA Decision, 16 DOMSC at 379-380, 398.

As such, the Siting Board considers the cost of the GOCC facility to reflect the lower end of a likely range of costs for a GOCC facility and the cost of a viable GOCC facility with a realistic fuel supply would fall between EEC's estimated costs for the GOCC alternative and NGCC alternatives. Thus, although the Company's GOCC alternative shows a levelized cost advantage of 3.12 $/MWh under the most favorable assumptions for that alternative, it is likely that a realistic fuel supply would result in a cost disadvantage for the

GOCC alternative, even under favorable assumptions.[231] Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to cost.

In comparing the cost of the proposed project with the CGCC alternative, the record demonstrates that, based on the heat rate provided by the Company and various facility configurations, coal types, and fuel price forecasts, the levelized cost of the CGCC alternative would range from 88.32 $/MWh to 98.60 $/MWh. The record further demonstrates that substituting 2.4 percent sulfur coal, consistent with the coal assumed by the Company for the proposed project, for the 1.8 percent sulfur coal assumed by the Company for the CGCC alternative, the levelized cost would decrease by approximately 1.45 percent. Assuming such a reduction for the lowest cost facility configuration -- an integrated 400 MW facility -- the levelized costs would decrease to 87.04 $/MWh, still greater than the cost of the proposed project.

The Attorney General raised concerns regarding the Company's calculation of capital costs and heat rate for the CGCC alternative. With respect to capital costs, the Attorney General's witness calculated that the capital costs of the CGCC alternative would be 2,067 $/kW in 1997 dollars, approximately 76 percent of the Company's initial capital cost estimate of 2,712 $/kW. The Company's estimate was based on data compiled by an industry-wide source while the Attorney General's estimate was based on theoretical facilities. Even though the Attorney General's estimate compared favorably to estimated capital costs of the proposed Wabash facility, the Wabash facility will utilize existing facilities, thereby lowering cost. In addition, although the Attorney General's cost estimate included certain design factors consistent with the proposed project, a number of site-specific and project-specific costs, such as costs of noise mitigation and wetlands protection, were not included. As such, the capital cost of a CGCC facility at the proposed site likely would be higher than the cost estimated by the Attorney General.

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[231] For example, assuming the levelized cost of the GOCC alternative is the midpoint between the Company's assumed levels for the GOCC and NGCC alternatives, the GOCC alternative would show a cost disadvantage of 3.23 $/MWh.

With respect to heat rate, the Attorney General's witness indicated that the heat rate of a CGCC facility, consistent with the proposed project, would be approximately 19 percent less than the heat rate estimated by the Company, leading to a reduction in costs. However, unlike the lower heat rate provided for the NGCC alternative which was based on a proposed facility, the heat rate estimates provided by the Attorney General for the CGCC alternative were based on theoretical facilities. There are no existing CGCC facilities with the characteristics of the theoretical facilities used as a basis for the Attorney General's heat rate estimates.

Finally, the record demonstrates that the availability factor assumed by the Company for the CGCC alternative, 85.5 percent, is representative of an availability factor for a mature technology rather than a technology that has not yet reached a mature status. Although an availability factor in the range of 85 percent is anticipated for the technology, there is no evidence in the record that operating facilities have achieved 85 percent availability or that currently proposed facilities anticipate this availability factor. Further, there is no assurance such an availability factor would be reached by operating facilities by the time the proposed project is expected to commence operation in 1997. With a decrease in the assumed availability factor of 85.5 percent, levelized costs of the CGCC alternative would increase.

Therefore, for the purposes of comparison, the Siting Board finds that reliance on the Company's analysis of comparative levelized costs for the CGCC alternative, including the capital cost and heat rate assumptions provided by the Company which are based on data compiled by an industry-wide source are preferable to reliance on the Attorney General's analyses based primarily on theoretical facilities. Accordingly, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to cost.

In comparing the cost of the proposed project to the PC alternative, the record demonstrates that the levelized cost of the PC alternative would range from 87.51 $/MWh to 89.99 $/MWh under the various fuel price forecasts. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the PC alternative with respect to cost.

In comparing the cost of the proposed project to the RO alternative, the record demonstrates that the levelized cost of the RO alternative would range from 118.77 $/MWh to 128.76 $/MWh under the various fuel price forecasts. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the RO alternative with respect to cost.

Finally, with respect to the MCC alternative, the record demonstrates that all aspects of NO-COAL's cost analysis are uncertain. The components of levelized cost, including fuel cost, capital cost and availability factor, were not substantiated by the TAG report or by data relative to proposed or existing facilities, consistent with cost estimates provided for other technology alternatives. Instead, cost and availability factors were based on the GOCC alternative. There are no existing or proposed facilities with a fuel supply similar to the fuel supply proposed by NO-COAL.

With regard to fuel price estimates, although a methanol supplier provided a specific fuel cost, there is no evidence in the record to support the assumption that such fuel costs would be achievable. All aspects of the MCC alternative that would affect fuel price, including feedstock source and price, plantship construction cost, and method of fuel delivery to the site, are uncertain. In addition, although the assumed availability factor is the availability factor of a NGCC facility, the greater likelihood of methanol supply interruptions due to the complex fuel supply arrangements could decrease availability in relation to a natural gas-fired facility. The evidence in the record does not substantiate NO-COAL's levelized cost projection for the MCC alternative. Accordingly, based on the foregoing, the Siting Board can make no finding regarding the comparison of cost of the proposed project and the MCC alternative.

6. Reliability

In this section the Siting Board compares the proposed project to the technology alternatives with respect to unit-specific reliability. As noted in Section II.B.2.a., above, in City of New Bedford the Court found the Siting Council's past practice of requiring a non-utility applicant to establish that its proposed plant was superior to alternative approaches in terms of cost, environmental impacts, reliability and ability to address a demonstrated need comported with their statutory mandate. 413 Mass. at 485. See also, Attorney General Brief at 97. The Siting Board notes that unit-specific reliability relates to the predictability of unit operation. As such, the Siting Board considers such factors as the anticipated availability, the maturity of the technology, and the reliability of the fuel supply in comparing the reliability of the proposed project with the reliability of the technology alternatives.

With respect to the proposed project, the Company indicated that the availability of the proposed project would be 85 percent (Exh. HO-AER-9(a)(A)). In addition, as noted above, the Company indicated that the CFB technology is a well-defined, advanced technology given that operation and permit data is available for a number of CFB facilities that have come on-line in recent years or are currently under development (Tr. 22, at 94-95; Tr. 23, at 133-134). With regard to fuel supply, the Siting Council recognized that the region which EEC had targeted for its coal supply contains large uncommitted coal reserves which would allow any of a number of producers to supply coal to the proposed project over its lifetime and that reliable rail transportation is available from the coal-producing region to the site. EEC Decision, 22 DOMSC at 309-310.[232]

In comparing the reliability of the proposed project to the reliability of the NGCC alternative, the Siting Board notes that the availability factor would be 90.5 percent, 6.5 percent greater than the availability factor of the proposed project (Exh. HO-AER-9(a)(A)). However, such a difference in availability of the two technologies, while indicating that NGCC would be slightly preferable to the proposed project in annual facility operation does not represent a significant difference for purposes of this review. In addition, the Siting Board notes that the NGCC technology is a well-defined and proven technology given the number of natural gas-fired combined cycle facilities that have come on line or have been

[232] The Siting Board notes that the Siting Council determined that at such time as EEC executes a coal supply agreement which includes terms similar to those found in its coal RFP, EEC will be able to establish that its proposed project meets the second test of viability. EEC Decision, 22 DOMSC at 310-312. Such a coal supply agreement was required by the Siting Council in its condition relating to project viability. Id. The Company has not yet filed its response to these conditions.

proposed in recent years. See, e.g, Enron Decision, 23 DOMSC at 7; West Lynn Decision, 22 DOMSC at 5; MASSPOWER Decision, 20 DOMSC at 305; Altresco Decision, 17 DOMSC at 354; NEA Decision, 16 DOMSC at 338. Further, the Siting Board has noted that while a 365-day firm gas supply may not be typical, it is a realistic approach which is likely to be both financeable and viable. See Section II.B.5.b., above. Accordingly, based on the foregoing, the Siting Board finds that, for purposes of this review, the NGCC alternative and the proposed project would be comparable with respect to reliability.

In comparing the proposed project to the GOCC alternative, the Siting Board notes that the record indicates that the availability factor and technology maturity of the GOCC alternative would be comparable to the NGCC alternative. However, the Siting Board notes that the GOCC alternative does not have a realistic fuel supply and likely would not be financeable or permittable based on the assumed fuel supply (see Section II.B.5.b., above). Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the GOCC alternative with respect to reliability.

With respect to the CGCC alternative, the Company assumed the TAG-specified availability factor of 85.5 percent which is representative of a mature technology in its cost analyses (Exh. HO-AER-9(a)(A)). In Section II.B.5.b., above, the Siting Board reviewed the Company's and parties arguments regarding the availability factor of the CGCC alternative. The Siting Board acknowledged that, although an availability factor in the range of 85 percent is expected over the long term for the technology, there is no evidence in the record that operating facilities have achieved 85 percent availability or that currently proposed facilities anticipate this availability factor. The Siting Board also acknowledged that there is no assurance that such an availability factor would be reached by operating facilities by the time the proposed project is expected to commence operation in 1997.

Therefore, the record demonstrates that the CGCC technology has not achieved an availability factor representative of a mature technology. A lower, more realistic availability factor would have a negative impact on the reliability and commercial viability of a CGCC facility intended for the same time frame as the proposed facility. Thus, based on the record in this proceeding, the CGCC alternative likely would not be a viable or reliable source of energy supply within the time frame in which the proposed facility would come on-line. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the CGCC alternative with respect to reliability.

With regard to the PC alternative, the record indicates the likely availability factor would be 84 percent (Exh. HO-AER-9(a)(A)). In addition, the Siting Board notes that the PC technology is a proven technology. Accordingly, based on the foregoing, the Siting Board finds that the proposed project and the PC alternative would be comparable with respect to reliability.

With regard to the RO alternative, the record indicates the likely availability factor would be 74.3 percent, 13 percent less than the availability of the proposed project (id.). However, such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the RO alternative in annual facility operation does not represent a significant difference for purposes of this review. The Siting Board notes that the RO technology is a proven technology. Nevertheless, based on the foregoing, the Siting Board finds that the proposed project is comparable to the RO alternative with respect to reliability.

Finally, with respect to the MCC alternative, NO-COAL assumed the same availability factor as the GOCC alternative and argued that the MCC alternative could provide a viable and reliable energy supply within the same time frame as the proposed project. In Section II.B.5.b., above, the Siting Board raised serious concerns regarding the potential reliability and viability of the MCC alternative. The Siting Board noted that there are no existing or proposed facilities with a fuel supply similar to the fuel supply proposed for the MCC alternative and that all aspects of the MCC alternative are uncertain. The Siting Board also noted that the likelihood of methanol supply interruptions due to the complex fuel supply arrangements could decrease availability. Accordingly, based on the foregoing, the Siting Board finds that the proposed project would be preferable to the MCC alternative with respect to reliability.

7. Comparison of the Proposed Project and Technology Alternatives

a. Comparison

In City of New Bedford, the Court stated that "the statute mandates that the [Siting C]ouncil balance environmental harm that would be caused by a new power plant against the other statutory objectives -- providing a necessary energy supply at the lowest possible cost." 413 Mass. at 485. In addition, the Court stated "[t]he statutory mandate, however, requires that the energy the facility will supply is necessary for the Commonwealth; that the supply of the energy involves a minimum impact on the environment; and that such energy is supplied at the lowest possible cost. Thus, the statutory balance involves weighing minimum environmental impact and cost." Id., 413 Mass. at 486. In addition, the Court stated that the Siting Council would need to explicitly state that it was approving a project with greater environmental impacts than alternatives on the basis of a determination that other factors outweighed those environmental impacts. Id. at 490. See also Attorney General Brief at 97.

In Section II.B.2.d, above, the Siting Board found that, in order to establish that a proposed project is preferable to technology alternatives in its ability to provide a necessary energy supply for the Commonwealth a minimum impact on the environment at the lowest possible cost, the Siting Board would require the applicant to establish that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need and in terms of cost, environmental impact and reliability.

In Sections II.B.4, II.B.5, II.B.6, above, the Siting Board has analyzed the record, as directed by the Court, by comparing the proposed project against generating technology alternatives that have been determined capable of meeting the identified need, on the basis of their specific impacts on the environment, costs and reliability.[233]

In comparing the environmental impacts of the proposed project to the environmental impacts of the technology alternatives, the Siting Board has found that (1) the NGCC and

[233] As noted in n.56, above, for purposes of this review of technology alternatives, the Siting Board assumed need based on the Siting Council finding in the EEC Decision. In Section II.C, below, the Siting Board reanalyzes need based on the updated information provided in the remand proceedings.

GOCC alternatives would be preferable to the proposed project with respect to environmental impacts, and (2) the proposed project would be preferable to the CGCC, PC and RO alternatives with respect to environmental impacts. In addition, the Siting Board could make no finding regarding the comparative environmental impacts of the proposed project and MCC alternative.

In comparing the costs of the proposed project to the costs of the technology alternatives, the Siting Board has found that the proposed project would be preferable to the NGCC, GOCC, CGCC, PC, and RO alternatives with respect to cost. In addition, the Siting Board could make no finding regarding the relative costs of the proposed project and the MCC alternative.

In comparing the reliability of the proposed project to the reliability of the technology alternatives, the Siting Board has found that (1) the proposed project would be preferable to the GOCC, CGCC, and MCC alternatives with respect to reliability, and (2) the proposed project would be comparable with respect to the NGCC, PC and RO alternatives with respect to reliability.

Thus, in comparing the environmental impacts, cost and reliability of the proposed project to the environmental impacts, cost and reliability of the technology alternatives, the Siting Board notes that: (1) the NGCC alternative would be preferable to the proposed project with respect to environmental impacts, the proposed project would be preferable to the NGCC alternative with respect to cost and the proposed project would be comparable to the NGCC alternative with respect to reliability; (2) the GOCC alternative would be preferable to the proposed project with respect to environmental impacts while the proposed project would be preferable to the GOCC alternative with respect to cost and reliability; (3) the proposed project would be preferable to the CGCC alternative with respect to environmental impacts, cost and reliability; (4) the proposed project would be preferable to the PC alternative with respect to both environmental impacts and cost and the proposed project would be comparable to the PC alternative with respect to reliability; (5) the proposed project would be preferable to the RO alternative with respect to both environmental impacts and cost and the proposed project would be comparable to the RO alternative with respect to reliability; and (6) the proposed project would be preferable to the MCC alternative with respect to reliability.

In balancing the environmental impacts, cost and reliability of the proposed project and the technology alternatives, the Siting Board first considers the proposed project in relation to the CGCC, PC, RO, MCC and GOCC alternatives. The Siting Board then considers the proposed project in relation to the NGCC alternative.

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

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

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

In comparing the proposed project to the MCC alternative, while the Siting Board could not make a finding on the overall preferability of either the proposed project or the MCC alternative with respect to environmental impacts, the Siting Board was able to determine that the MCC alternative would be preferable with respect to air quality while the proposed project would be preferable with respect to fuel transportation. For all other categories of environmental impacts as well as for cost, there was insufficient evidence regarding the MCC alternative in the record for the Siting Board to determine which of the two technologies would be preferable. Further, the Siting Board has found that the proposed project would be preferable to the MCC alternative with respect to reliability. While the MCC alternative has an advantage to the proposed project with respect to air quality, the Siting Board finds that this benefit of the MCC alternative does not outweigh its potential for greater fuel transportation impacts or the lack of demonstrated preferability in other categories of environmental impacts and in cost. Further, the Siting Board finds that the air quality benefits are insufficient to outweigh the reliability disadvantages due to its unproven status. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the MCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

As noted above, the Siting Board has found that the GOCC alternative would be preferable with respect to environmental impacts. However, the proposed project would be preferable with respect to cost. Further, the Siting Board has found that the proposed project would be preferable with respect to reliability as the GOCC alternative does not have a realistic fuel supply and likely would not be financeable or permittable based on the assumed fuel supply (see Sections II.B.5.b, and II.B.6, above). The Siting Board finds that the environmental advantage of the GOCC alternative does not outweigh its cost and reliability disadvantages relative to the proposed project. Accordingly, based on the foregoing, the Siting Board finds that the proposed project is superior to the GOCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

With respect to the NGCC alternative, the Siting Board found that the NGCC alternative would be preferable to the proposed project with respect to environmental impacts while the proposed project would be preferable to the NGCC alternative with respect to cost. Further, the Siting Board has found that the proposed project would be comparable to the NGCC alternative with respect to reliability, noting that while a 365-day firm gas supply is not typical, it is a realistic approach which is likely to be both financeable and viable.

In determining that the NGCC alternative would be preferable to the proposed project with respect to environmental impacts, the Siting Board found that: (1) the NGCC alternative would be preferable with respect to air quality, solid waste and land use impacts; (2) the proposed project would be preferable with respect to water supply impacts; and (3) that the two technologies would be comparable with respect to wastewater and noise impacts. In addition, the Siting Board could make no finding regarding the relative fuel transportation impacts of the two technologies.

In considering the overall environmental impacts of the two technologies, the Siting Board noted that the advantage of the NGCC alternative was limited with respect to solid waste and land use impacts, and that the advantage of the proposed project was limited with respect to water supply impacts. Thus, the only impact area in which the NGCC alternative has a significant advantage relative to the proposed project is in the area of air quality. However, we have also found that the proposed project would have a significant cost advantage. Therefore, the Siting Board must weigh the air quality benefits of the NGCC alternative against the cost benefits of the proposed project to determine which would be superior. In order to do so, we must first assess the relative value of these benefits. The Siting Board notes that such as assessment was not necessary in comparing the proposed project to the other alternatives in light of the clear superiority of the proposed project.

In assessing the air quality impacts of the two technologies, the Siting Board reviews the comparison of the two technologies with respect to the amount of pollutants that would be emitted, local air quality impacts and regional air quality impacts. With regard to the amount of pollutants that would be emitted, the Siting Board notes that, relative to the proposed project, the NGCC alternative would emit significantly less for all pollutant categories with the exception of VOC emissions.[234] In addition, considering the potential

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[234] Specifically, relative to the proposed project, the NGCC alternative would emit: (1) approximately 15 percent of the NOx emissions, or 1,455 tpy less; (2) approximately 0.8 percent of the SO_2 emissions, or 2,599 tpy less; (3) approximately 33 percent of the CO emissions, or 996 tpy less; (4) approximately 155 percent of the VOC emissions, or 38 tpy more; (5) approximately 18 percent of
(continued...)

improvement in the heat rate of the NGCC alternative, the NGCC emissions could further decrease. See Section II.B.4.b.i.(A)(1), above.

With respect to air quality impacts resulting from the above emissions, the Company has provided analyses addressing the local New Bedford area impacts, as well as broader impacts in Massachusetts and New England as a whole. For the local area, the Company's refined air quality modeling analysis for the proposed project reflected existing concentrations of criteria pollutants in the New Bedford area that are well within NAAQS. Further, the Company's analysis indicates that the impacts of the proposed project and the NGCC alternative on ambient concentrations of criteria pollutants are less than 1.6 percent of NAAQS for all such criteria pollutants under all averaging periods. The emissions from the NGCC alternative would be less than those from the proposed project for all pollutants, and would be less than one-half those from the proposed project for 3-hour NOx, annual and 24-hour SO_2, and annual PM-10. See Section II.B.4.b.i.(A)(2), above.

The record also indicates that emissions of criteria pollutants from the proposed project and the NGCC alternative also potentially would affect air quality problems that are regional or global in scale -- notably, ground-level ozone and acid rain. Ozone is formed in the atmosphere from emissions of NOx and VOCs, and is of particular concern given that all of Massachusetts is classified as non-attainment for that pollutant. Acid rain also results from NOx emissions, as well as from SO_2 emissions. The proposed project's SO_2 emissions were addressed in detail in the EEC Compliance Decision, which required additional mitigation and encouraged the Company to pursue an offset plan it proposed as a means to achieve even greater emissions reductions while also minimizing costs.[235] In addition, the possible impact of CO_2 emissions is a global air quality concern. Like SO_2, CO_2 emissions were

[234](...continued)
the PM-10 emissions, or 168 tpy less; and (6) approximately 56 percent of the CO_2 emissions, or 1,021,000 tpy less.

[235] Besides helping to address acid rain concerns, additional SO_2 reductions through offsets would benefit local air quality in the vicinity of the facility providing the offsets.

addressed in detail in the EEC Compliance Decision, which required CO_2 offsets not currently required under state or federal environmental statutes.

Of significance to regional and global impacts, the Company did provide a five-year dispatch analysis that compared emissions from the proposed project to emissions from existing generating facilities that would be displaced by the proposed project. The analysis indicated that the proposed project would produce significantly lower emissions per kwh of important pollutants -- notably NOx and SO_2 -- than many existing generating units. The Siting Board has found that the Company's dispatch analysis establishes that the proposed project likely would provide short-term air quality benefits for Massachusetts and New England based on modeled dispatch effects. Further the Siting Board has recognized that, to the extent the proposed project, in whole or in part, effectively would replace existing generation that potentially will be permanently retired, there is a significant potential for the proposed project to provide long-term environmental benefits through displacement of such generation.[236] See Section II.B.4.b.ii., above.

Turning to a comparison of the cost of the proposed project and the NGCC alternative, the Siting Board has found that the levelized cost, in 1997 dollars, of the proposed project would be 83.09 $/MWh while the levelized cost, in 1997 dollars, of the NGCC alternative would range from 92.67 $/MWh to 104.68 $/MWh (see Section II.B.5., above). In comparing the cost differential on an annual basis, the Siting Board notes that in developing the 20-year levelized costs, the Company assumed an availability factor of 85 percent for the proposed project and an availability factor of 90.5 percent for the NGCC alternative. Therefore, the annual levelized cost, in 1997 dollars for the proposed project, would be $185,606,442, and the annual levelized cost, in 1997 dollars for the NGCC alternative, would range from $220,400,768 to $248,964,631. The difference in the annual levelized cost of the NGCC alternative and proposed project, in 1997 dollars, would range from $34,794,326 to $63,359,189. Thus, the annual levelized cost of the NGCC alternative would

236 In addition, the Siting Board found that the Company's dispatch analysis does not establish that the project would provide significant long-term air quality benefits based on the modeled dispatch effects (see Section II.B.4.b.ii., above).

represent an 18.7 percent to 34.1 percent increase over the annual levelized cost of the proposed project.[237]

Each technology, therefore, offers a significant advantage relative to the other. In order to determine whether the proposed project or the generic NGCC alternative is superior, as directed by the Court, the Siting Board must weigh the environmental benefit of the NGCC alternative against the cost benefit of the proposed projects. Specifically, the Siting Board must weigh the air quality impacts of the proposed project relative to the NGCC alternative against the 18.7 percent to 34.1 percent annual levelized cost benefit of the proposed project relative to the NGCC alternative. As the Court has given no specific direction as to how the Siting Board should balance these statutory objectives, the Siting Board looks to the language of its statute for guidance.

The Siting Board notes that its statutory mandate is "to implement the energy policies contained in sections sixty-nine H to sixty-nine Q, inclusive, 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. As an initial matter, therefore, the Siting Board finds that to be consistent with the mandate of the statute, the focus of any analysis, weighing or balancing must be the Commonwealth's energy supply. Further, in providing this necessary energy supply for the Commonwealth, the Siting Board is directed by the statute to implement those policies contained in Sections 69H to 69Q. Thus, the Siting Board finds that any analysis, weighing or balancing undertaken in providing a necessary energy supply must be done in a manner that is consistent with implementing the policies of the statute.

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237 As discussed in Section II.B.5., above, the Siting Board recognizes that the cost of the NGCC alternative represents the high end of the likely range of costs for a natural gas-fired facility due to reliance on a 365-day firm gas supply. In addition, as also noted above, the Company's cost analysis is conservative with respect to the cost of the proposed project in relation to the NGCC alternative in two respects, (1) the levelized costs for the proposed project and alternative technologies were determined over 20 years, and (2) the capital cost of the proposed project includes project-specific costs that were not included for the NGCC alternative (see Section II.B.5.b, above).

In reviewing sections 69H to 69Q for relevant policies, the Siting Board notes that, in reviewing long-range forecasts, the Siting Board must determine that electric companies have plans that will meet their needs. G.L. c. 164, § 69I. The policy implicit in this directive is that the Siting Board must determine that the electric company has reliable sources of energy to supply its customers.[238]

Further, the Siting Board's statute gives the Siting Board the tools to ensure that an electric company is able to provide necessary energy to its customers. Thus, if an electric company's plan necessitated an electric company petitioning the Siting Board to override a local or state standard or for the right to exercise the power of eminent domain in order to be able to construct a new facility, the Siting Board is empowered with such authority.[239] The Siting Board finds that it is clear from the nature of these policies, that the Siting Board has the authority to accept increased environmental impacts or costs[240] if justified for purposes

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238 The Siting Board also notes that another policy contained in our statute requires the Siting Board to determine that plans for the expansion and construction of new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

239 G.L. c. 164, § 69K provides the Siting Board with the authority to override a standard imposed by a state or local agency that prevents an electric company from meeting that standard with commercially available equipment or if such agency inappropriately delayed any necessary approval, consent, permit or certificate. G.L. c. 164, § 69R allows the Siting Board to approve a petition of an electric company for the right to exercise the power of eminent domain over land interests necessary for the construction of an energy facility. Thus, the Siting Board's statute provides tools for the Siting Board to use in order to provide necessary energy resources in the event that an environmental, safety, land use, or other issue prevents the construction or operation of a facility.

240 In City of New Bedford, the court noted that the Siting Council must explicitly state the basis of its determination, with adequate subsidiary findings to support its conclusions. 413 Mass. at 491. The Court's directive that the Siting Council must balance environmental impacts and costs implies that the Siting Board could determine that cost outweighed environmental impacts provided that the basis for such a determination was explicit and consistent with statutory objectives.

of providing a necessary energy supply that is reliable.[241] Therefore, in implementing the policies contained in the Siting Board statute, the Siting Board finds that as the existing energy supply has associated environmental impacts, costs, and reliability considerations, any proposed addition to the Commonwealth's energy supply must be considered in light of the existing mix of energy resources and the environmental impacts, costs and reliability of that mix. The Siting Board, therefore, will determine, the relative value to the Commonwealth's energy supply of the specific environmental impacts and costs of the proposed project and the NGCC alternative in this case in light of the existing mix of resources. Based on the relative values of these benefits the Siting Board will be able to determine the appropriate weight which should be applied in the balancing of the statutory objectives.

The Siting Board notes that a reliable energy supply is one that among other things, will not be unduly restricted due to interruptions in supply of fuel resources.[242] A fuel supply that is overly dependent on one type of fuel, similar to an electric company plan that is overly dependent on one or a few energy resource options, would prevent the provision of necessary energy during times when that fuel supply was restricted. As noted above, a fuel supply which lacks diversity (i.e., is overly dependant on one type of fuel) would be vulnerable to reduced reliability. Thus, the Siting Board reviews the fuel supply underlying the Commonwealth's energy supply to identify reliability considerations relevant to a comparison of alternatives.[243]

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241 Such a conclusion is also consistent with the Siting Commission's Third Report in which they indicate that the proposed siting bill sought to mitigate environmental challenges which were perceived as delaying new and needed capacity (Third Report at 8, 9, 15). Further, the Siting Commission sought to address concerns that devices required for environmental protection and enhancement would reverse the long-term trend of decreasing average costs for electricity (id.).

242 The Siting Board notes that other issues relative to the reliability of the electric energy supply as a whole include transmission and distribution system reliability.

243 The Siting Board notes that the Siting Council recognized diversity as an important factor in achieving both a reliable and least-cost energy supply throughout reviews of both facility and utility forecast/supply plan reviews. See, e.g., Massachusetts Electric (continued...)

As indicated in the EEC Decision, in 1989 Massachusetts depended on oil-fired generation to meet 49 percent of its electric power needs. 22 DOMSC at 289. Further, as of January 1, 1990, less than 13 percent of the Commonwealth's generating capability was provided by coal and in 1989, 12 percent was provided by natural gas. Id. In the EEC Decision, the Siting Council stated that, despite the concerns raised by EEC regarding the increased reliance on natural gas in the state and region and the associated issues regarding the availability and price of gas,[244] "the significant environmental benefits of gas as a fuel for both power generation and other uses, and the minimal percentage of gas currently present in the state's and region's fuel mix, suggests that the region is a long way from any risk of overdependence on gas." 22 DOMSC at 293. However, the Siting Council went on to say "that diversity cannot be achieved by reliance on additions of just one fuel type or one technology. Even if sufficient new gas-fired facilities could be constructed and placed in operation in time to meet all of the region's need for additional capacity, elimination of alternative options still would be unwise. Clearly, both Massachusetts and the region need to increase their reliance on as many types of non-oil supply options as possible while maintaining an appropriate balance between cost, environmental impacts and reliability." Id. at 293-294. In conclusion, the Siting Council agreed with EEC "that the addition of the proposed project generally would enhance the diversity of the state's and the region's power generation resource mix." id. at 295.[245]

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[243](...continued)
Company and New England Electric System, 18 DOMSC at 336, 363-365 (1989); Eastern Utilities Associates, 18 DOMSC at 100, 131 (1989).

[244] EEC raised concerns relating to gas price ties to oil price in new long-term gas contracts. EEC Decision, 22 DOMSC at 290.

[245] The Siting Board notes that this discussion of diversity was in Section II.B.2. of the EEC Decision regarding consistency with policies of Commonwealth. In noting the Siting Council's statements, the Siting Board is not attempting to elevate the issue of consistency with policies over a balancing of environmental impacts, cost and reliability in meeting the need for additional energy resources; rather, the Siting Board recognizes that a balancing of the statutory objectives must be done in a way that is consistent with the policies of the Commonwealth.

A review of the 1992 CELT report (Exh. HO-70) indicates that, while the contribution from natural gas-fired generation to both the Massachusetts and regional energy supply as a result of new gas-fired generating resources has continued to increase, the contribution of coal-fired generation is decreasing.[246] Further, the 1992 CELT report indicates significant potential to increase gas-fired generation in Massachusetts and the region through the conversion of existing oil/gas dual-fuel units to primarily gas-fired units. The Siting Board notes that such conversions would be consistent with the energy and environmental policies in response to the Clean Air Act and could be accomplished without the need for significant facility modifications or additional generating facility siting review. The Siting Board also recognizes that the State Energy Plan calls for continued decreases in reliance on oil and consideration of retirement of older, inefficient units (pp. 13, 28-29).[247]

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246 With respect to new gas-fired facilities, the Siting Board notes that the Siting Council has approved five such facilities (approximately 1,000 MW combined), the Siting Board has approved the site banking of one additional facility (306 MW), and that petitions to construct two additional gas-fired facilities (approximately 400 MW) are currently under review by the Siting Board.

With respect to new coal-fired facilities, the Siting Board notes that this is the first coal-fired project to be reviewed by the Siting Council or Siting Board. However, the Siting Board is aware of one 20 MW coal-fired project that was recently constructed in Massachusetts of which all the power was sold to a New Hampshire utility. See Turners Falls Limited Partnership, 18 DOMSC 141 at 144 (1988). The Siting Board currently is reviewing a petition to construct the Taunton Energy Center, a 170 MW coal-fired project in Taunton, Massachusetts of which 30 MW is under contract to a Massachusetts municipal electric company. In addition, the AES Thames facility is a 180 MW coal-fired project, recently completed in Connecticut, power from which will be sold to Northeast Utilities for distribution to its subsidiaries, some of which provide power to Massachusetts customers (Exh. HO-70). Finally, a 72.5 MW coal-fired project is proposed for construction in Rhode Island (Newbay), 32.3 MW of which is under contract to eleven Massachusetts municipal electric companies (id.). The Siting Board notes that the Newbay and Taunton Energy Center contracts are currently under review at the Department and these two projects are further behind the proposed project in the permitting process.

247 The Siting Board notes that the State Energy Plan also calls for increased cost-effective (continued...)

Despite the increase in gas-fired generation experienced in the state and region thus far, the Siting Board recognizes that there is still a need for additional gas-fired generation for system-wide reliability purposes. Similarly, the evidence with regard to the rate at which new gas-fired generation and new coal-fired generation are being added to the state's and region's mix of energy resources indicates that there is an even greater need to add low-cost, environmentally-sound, coal-fired generation for system wide reliability purposes.[248,249]

The Siting Board has found, based on the record in this proceeding, that the proposed project is preferable to both the CGCC and PC alternatives with respect to both cost and environmental impacts. See Sections II.B.4.g., II.B.5.b., above. Further, the proposed project includes significant environmental mitigation measures as described in the EEC Decision and the EEC Compliance Decision, and has been shown to be the least cost approach to meeting the need relative to the alternatives reviewed. See Section II.B.5.b., above. The Company's dispatch analysis further demonstrates that the proposed project offers significant cost and environmental benefits relative to existing generating units. See Section II.B.4.b.ii., above.

While the Siting Board has found that the NGCC alternative offers greater environmental benefits to the energy supply relative to the proposed project, the Siting Board

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[247](...continued)
DSM (pp. 26-27). However, the need analysis shows a need for additional generation in addition to likely levels of DSM. See Sections II.C.3.b, II.C.4.b., below.

[248] The Siting Board notes that the legislature has expressly recognized the value of coal-fired units in reducing dependency on oil. See G.L. c. 164, §95G1/2. That statute, first enacted in 1980 (St. 1980, c. 464), has been repeatedly amended, including an amendment as recent as 1990 (St. 1984, c. 395, §1; St. 1986, c. 557, § 146; St. 190, c. 177, §350). The Siting Board notes that such action by the legislature supports the inference that the use of coal, with environmental safeguards, is appropriate as a part of the fuel mix to provide necessary energy to the Commonwealth and to decrease the Commonwealth's dependence on oil.

[249] The Siting Board here is not making a determination as to what the ultimate levels of gas or coal should be in the Commonwealth's energy supply mix, but rather is indicating that the Commonwealth has not yet reached such ultimate levels.

has also found that the proposed project offers greater cost and reliability benefits to the energy supply relative to the NGCC alternative. Further, the Siting Board finds that the increases in state and regional reliance on natural gas reduces the value to the energy supply associated with the environmental benefits of the NGCC alternative relative to the value to the energy supply associated with the cost and reliability benefits of the proposed project. Therefore, the Siting Board finds that in balancing the specific environmental impacts and costs of the proposed project against those of the NGCC alternative, in light of the environmental, cost and reliability characteristics of the existing energy supply, it is appropriate to give less weight to the specific environmental benefits offered by the NGCC alternative relative to the specific cost benefits offered by the proposed project. As such, the Siting Board finds that the cost benefits of the proposed project outweigh the environmental benefits of the NGCC alternative. The Siting Board further finds that, on balance, the proposed project is superior to the NGCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

b. <u>Findings and Conclusions</u>

The Siting Board has found that:

- the proposed project is superior to the CGCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 154);
- the proposed project is superior to the PC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 154);
- the proposed project is superior to the RO alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 154);
- the proposed project is superior to the MCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 155);

- the proposed project is superior to the GOCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 155);
- to be consistent with the mandate of the statute, the focus of any analysis, weighing or balancing must be the Commonwealth's energy supply (p. 159);
- that any analysis, weighing or balancing undertaken in providing a necessary energy supply must be done in a manner that is consistent with implementing the policies of the statute (p. 159);
- it is clear from the nature of these policies, that the Siting Board has the authority to accept increased environmental impacts or costs if justified for purposes of providing a necessary energy supply that is reliable (pp. 160-161);
- as the existing energy supply has associated environmental impacts, costs, and reliability considerations, any proposed addition to the Commonwealth's energy supply must be considered in light of the existing mix of energy resources and the environmental impacts, costs and reliability of that mix (p. 161);
- in balancing the specific environmental impacts and costs of the proposed project against those of the NGCC alternative, in light of the environmental, cost and reliability characteristics of the existing energy supply, it is appropriate to give less weight to the specific environmental benefits offered by the NGCC alternative relative to the specific cost benefits of the proposed project (p. 165);
- the cost benefits of the proposed project outweigh the environmental benefits of the NGCC alternative (p. 165); and
- on balance, the proposed project is superior to the NGCC alternative with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost (p. 165).

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

C. Need Analysis

In this section the Siting Board first reviews the evolution of its standard of review for the analysis of need for non-utility developers, then considers what is meant by a "necessary" energy supply in light of the Court's comments in City of New Bedford. The Siting Board next reviews the Court's directive as it relates to the issue of need and the arguments of the parties with regard to the appropriate standard of review that the Siting Board should use for its analysis of need. After setting forth a standard of review that is responsive to the Court's directive, the Siting Board evaluates the record for both the region's and the Commonwealth's need for energy resources.

1. The Development of the Siting Council's Standard of Review for Non-Utility Developers

In addition to developing a standard of review for the comparison of alternatives in the NEA Decision, the Siting Council also had to establish a standard of review for the analysis of need. An analysis of G.L. c. 164, § 69I showed that new energy facilities must be consistent with an approved long-range forecast. Further, G.L. c. 164, § 69J required that long-range forecasts be "consistent with the policies stated in section sixty-nine H to provide a necessary power supply for the [c]ommonwealth ...." As such, the Siting Council concluded that it was required to find that there was a need for additional power resources before approving a proposed energy facility. NEA Decision, 16 DOMSC at 344, citing, Boston Edison Company, 13 DOMSC 63, 67-78 (1985). Accordingly, the Siting Council commenced its review of NEA's petition to construct a bulk generating facility by analyzing the need for additional energy resources.

In its past decisions on the issue of need for utility facilities, the Siting Council found that the determination of whether there was a need for additional energy resources required the Siting Council to review electric utilities' long-range supply plans under a reasonable range of contingencies. Boston Edison Company, 15 DOMSC 241, 300-302 (1987) ("1987 BECo Decision"). The Siting Council had also found that additional capacity would be needed where projected future capacity available to the system was inadequate to satisfy projected load and reserve requirements. Cambridge Electric Light Department, 15 DOMSC

187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985) ("1985 MECo Decision"). In addition, the Siting Council had found that new capacity was needed in order to ensure that service could be maintained in the event of a reasonably likely contingency. Nantucket Electric Company, 15 DOMSC 363, 380-383 (1987); 1985 MECo Decision, 13 DOMSC at 137 (1985). Further, the Siting Council had found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. 1985 MECo Decision, 13 DOMSC at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

The Siting Council also found that in past reviews of proposals of Massachusetts electric utilities to construct energy facilities in the Commonwealth, that those facilities might be needed to meet New England's energy needs. Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); 1985 MECo Decision, 13 DOMSC at 129-131, 133, 138, 141; Massachusetts Electric Company, 2 DOMSC 1, 4-6 (1977). The Siting Council had made this determination after reviewing G.L. c. 164, § 69J and its legislative history, which recognizes the interconnected nature of the region's electric system and the reliability and economic benefits that flow to Massachusetts from the state's utilities' participation in NEPOOL. NEA Decision, 16 DOMSC at 347.

Thus, in the NEA Decision, the Siting Council concluded that:

> [W]here a non-utility-company developer seeks to construct a jurisdictional QF facility (or a jurisdictional facility supporting a QF project) principally for a single specific utility purchaser, the Siting Council requires the applicant to demonstrate that the utility needs the facility to address reliability concerns or economic efficiency goals ... If [the company] shows that it is proposing to construct a QF in Massachusetts to serve a number of power purchasers in the region, some as yet unknown, then it must demonstrate (1) that New England needs the proposed additional power resources in the proposed time period, and (2) that Massachusetts is likely to receive reliability or economic efficiency

> benefits from the proposed additional power resources during the same time frame.[250]

Id., 16 DOMSC at 349-350. The Siting Council then applied this standard to the review of NEA's application.

At the time of NEA's application, 150 MW of the proposed facility's 300 MW capacity was under contract to three Massachusetts electric utilities. An additional, 120 MW was also expected to be sold to those three utilities. The remaining 30 MW was to be marketed to other New England utilities. Id., 16 DOMSC at 339. Thus, in the NEA Decision, the Siting Council considered whether New England needed the 300 MW based upon a reliability rationale, i.e., whether projected capacity in New England was inadequate to satisfy the region's projected load and reserve needs. Id., 16 DOMSC at 351.

NEA relied on several forecasts that looked at various contingencies similar to the method used by the Siting Council in its review of utility long-range forecasts.[251] Id., 16 DOMSC at 351-354. Consistent with G.L. c. 164, § 69J, which requires an adequate consideration of C&LM in the projections of the demand for electric power, NEA also provided forecasts of demand and supply that incorporated estimates of C&LM. Id., 16 DOMSC at 371. Additionally, the Siting Council found that NEA had established that Massachusetts was likely to receive reliability and economic benefits from the additional

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250 Although the New England component of this standard recognizes the interconnected nature of the New England electric power market, the final component establishes the need for the new energy resources in the Commonwealth. Were a developer of a proposed QF in Massachusetts unable to demonstrate that the forecasts of need indicated a likelihood of reliability or economic efficiency benefits accruing to Massachusetts' electric utilities and ratepayers, the developer would have been unable to show that the proposed project would provide a necessary energy supply for the Commonwealth.

251 As required by G.L. c. 164, § 69J, for the approval of a long-range forecast, the Siting Council found that NEA had provided projections of the demand for electric power and the capacities of existing and proposed facilities that were based on accurate historical information and reasonable statistical projection methods. NEA Decision, 16 DOMSC at 354.

power resources from its proposed facility.[252] Id., 16 DOMSC at 354-360. Further, the Siting Council found that the requirement set forth in Section 69J that proposed facilities be consistent with the resource use and development policies as adopted by the Commonwealth was achieved by the addition of cost-effective QF resources to an electric utility's supply mix. Id., 16 DOMSC at 358.

The Siting Council's review of Altresco's petition followed closely the analysis established in the NEA Decision. Altresco demonstrated that there was a need for the proposed additional power resources for New England and that Massachusetts was likely to receive reliability or economic efficiency benefits from the proposed additional power resources so that construction of the proposed project in the state was consistent with the energy needs, and resource use and development policies of the Commonwealth. Altresco Decision, 17 DOMSC at 365-369. The Siting Council noted that in addition to reliability or economic efficiency benefits to be realized from a power sales agreement with the Massachusetts Electric Company ("MECo"), a Massachusetts electric utility, economic and environmental benefits, as a result of the steam sales agreement and the replacement of the oil-fired boilers of the steam host, would be realized from the proposed project. Id., 17 DOMSC at 369.

In the review of MASSPOWER's petition, the Siting Council reviewed MASSPOWER's analysis of need consistent with earlier Siting Council cases, including the two previously discussed non-utility facility cases, and found that MASSPOWER had presented a reasonable range of plausible demand and supply forecasts and had demonstrated that New England had a need for at least the capacity of its proposed project. MASSPOWER Decision, 20 DOMSC at 322. The Siting Council did, however, find fault with that part of the need analysis which relied on dated material, and emphasized that

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[252] For example, the Siting Council found that the existence of signed and Department approved power sales agreements with Massachusetts' electric utilities constituted evidence of the utilities' need for power for economic efficiency reasons. NEA Decision, 16 DOMSC at 359. The Siting Council further found that where such contracts included a capacity payment to the QF, they would also provide evidence of the utilities' need for additional power resources for reliability purposes. Id.

project proponents must utilize the most current information available for forecasting purposes. Id., 20 DOMSC at 321.[253]

The Siting Council then reviewed the benefits that Massachusetts would receive from the proposed project and further developed its rationale for the purpose of a Massachusetts benefits test. Id., 20 DOMSC at 334. The Siting Council raised two points with regard to these benefits. First, the level of the benefits required must be commensurate with the size and nature of the proposed facility. Id. Second, the Massachusetts benefits test has to be weighed against the recognition of the interrelationship of Massachusetts' energy supply and the regional system. Id. The Siting Council concluded that the Massachusetts benefit standard should be set to allow the Commonwealth to be a host to necessary, least-cost, least-environmental-impact generating projects designed to serve the entire region, while ensuring that they bring some meaningful benefit to Massachusetts.[254] Id.

In the MASSPOWER Decision, the Siting Council was also faced with the situation wherein the petitioner had no signed and approved PPAs, but had established that it was in the award group for three Massachusetts' utilities' solicitations for power.[255] The Siting

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[253] The Siting Council also found that MASSPOWER had presented a more comprehensive analysis of important variables in its assessment of regional need than in prior Siting Council reviews; nevertheless, the Siting Council noted that several important variables affecting regional need had not been included. MASSPOWER Decision, 20 DOMSC at 322. As a result, the Siting Council noted that in the future, project proponents would be required "to provide a more comprehensive assessment of regional need including a sensitivity analysis of major variables affecting regional need. Id.

[254] The Siting Council recognized that "[t]he New England region's generating and transmission system is a unified whole, and any parochialism by Massachusetts in rejecting facilities which may not be of immediate benefit to Massachusetts may lead other states to disapprove the siting of facilities which are of significant benefit to Massachusetts." MASSPOWER Decision, 20 DOMSC at 334.

[255] Pursuant to Department regulations, Massachusetts utilities that have identified a need for additional capacity or power offer a Request For Proposals ("RFP") to meet that need. The bids that are submitted are rated by the procuring utility, and a group is selected to enter into negotiations with the utility for a PPA. The selected group is (continued...)

Council acknowledged that non-utility developers may seek approval of their proposed projects before PPAs are signed and approved, or before inclusion in any utility's award group. Id., 20 DOMSC at 335. The Siting Council realized that one barrier to inclusion in an award group is the perception that a proposed project may not be permitted or built. As such, the Siting Council recognized that developers may seek Siting Council approval at an early stage of power marketing. Id. The Siting Council went on to say:

> we believe that it is important for our process to allow facility developers to obtain, when warranted, Siting Council approval relatively early in the development process. The Siting Council does not believe there are insurmountable barriers to a showing that allows Siting Council approval before the marketing of power is final. In those cases, it simply is important for proponents to establish meaningful benefits to Massachusetts that are not associated with power sales.

Id. Thus, the Siting Council acknowledged the need for a process that would allow sufficient time for both the review of a proposed project and its construction, in order to provide a necessary energy supply for the Commonwealth at the time the need was projected, without restricting a developer's showing of Massachusetts need to signed and approved PPAs.[256,257]

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[255](...continued)
known as the award group. Inclusion in an award group, although increasing the likelihood that power or capacity will be sold to the procuring utility by the members of the award group, does not guarantee that a PPA will be signed with that utility or that the contract will be approved by the appropriate regulatory authority.

[256] The Siting Council's acknowledgement that signed and approved PPAs should not be the only method of demonstrating need for a proposed project is a recognition that non-utility developers may seek approval of their proposed projects before all marketing of the power has been completed. Seeking approval at such an early stage of development is consistent with the stated rationale of the Siting Commission for the requirement that electric utilities submit long-range forecasts that identified planned additional facilities. The Siting Commission noted that this requirement would bring the utilities' "complete plans before the public at an advanced date and subject to state approval, thereby ensuring that the best interests of the consumer are being considered and safeguarded." Third Report at 20.

In West Lynn's petition to the Siting Council, West Lynn provided an analysis of need in the manner accepted by the Siting Council in its review of the earlier three non-utility petitions. Based on this analysis, the Siting Council found that West Lynn had established that New England would need additional energy resources in an amount at least equal to the proposed project's output for reliability purposes. West Lynn Decision, 22 DOMSC at 36.

The Siting Council then turned to its review of the benefits that would accrue to Massachusetts from the proposed project. As in the MASSPOWER Decision, the Siting Council found that West Lynn had no signed and approved PPAs and, as such, found that West Lynn had not established that its proposed project offered economic efficiency or reliability benefits to the Commonwealth. 22 DOMSC at 39-40. In fact, although West Lynn planned to bid in at least three utility RFPs for electric power, at the completion of the West Lynn proceedings, West Lynn was not even a member of the award group in any utility bidding. Id., 22 DOMSC at 39. The Siting Council did find, however, that Massachusetts would receive economic benefits from steam sales and, as a result of a large portion of those

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[257](...continued)

[257] The Siting Council found that although MASSPOWER had not established that its proposed project would offer reliability or economic efficiency benefits to the Commonwealth, there was some likelihood, due to its inclusion in the several award groups, that the proposed project eventually would have signed and approved contracts, and, therefore, would be able to meet the second part of the Massachusetts benefits test. MASSPOWER Decision, 20 DOMSC at 334. As such, the Siting Council found that if MASSPOWER provided evidence of at least one signed and approved PPA with a Massachusetts utility, of at least the size of the proposed 54 MW contract with Western Massachusetts Electric Company, in addition to the other recognized benefits to Massachusetts, the Massachusetts benefits test would be met. Id., 20 DOMSC at 334-335.

MASSPOWER provided copies of such agreements, including a signed and approved PPA, on November 19 and December 6, 1990. MASSPOWER, Inc., 21 DOMSC 196, 199 (1990) ("MASSPOWER Compliance Decision"). After review of the documents, the Siting Council found that MASSPOWER had complied with the conditions set forth in the MASSPOWER Decision, and that the construction of the proposed project was consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. MASSPOWER Compliance Decision, 21 DOMSC at 205.

steam sales, a substitution of direct thermal energy would replace electricity as a means of producing refrigeration thereby achieving a measure of electricity conservation for Massachusetts and New England. Id., 22 DOMSC at 42. In addition, subject to West Lynn providing further documentation of executed agreements on the use of West Lynn's steam host's wastewater discharge and the use of wastewater effluent from the Lynn Water and Sewer Commission, the Siting Council found that West Lynn could establish that additional economic benefits and environmental benefits relating to water quality would be provided to Massachusetts. Id., 22 DOMSC at 45, 47. The Siting Council then concluded that, upon confirmation that West Lynn had signed and executed agreements relative to the above referenced use of wastewater, the proposed project would provide benefits to the Commonwealth of sufficient magnitude to offset the impacts to the Commonwealth's resources from construction and operation of the proposed facility. Id., 22 DOMSC at 51.

During the development of the record in the EEC proceeding, EEC provided the most comprehensive analysis of regional need ever provided to the Siting Council. EEC Decision, 22 DOMSC at 233. Although the Siting Council dismissed various of the forecasts provided on the basis that they were multiple forecasts which used essentially the same assumptions and methodologies, the Siting Council concluded that the remaining 356 need cases provided credible evidence of the need for the proposed project. Id., 22 DOMSC at 234, 241. Of these 356 cases, 88 percent showed a need for additional energy resources at least in an amount equal to the output of the proposed project by the first year of the proposed project's completion. Id., 22 DOMSC at 241.[258]

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[258] The Siting Council noted that EEC had presented a comprehensive set of resource contingencies that addressed most of the important contingencies that had been identified by the Siting Council in previous reviews of regional need. EEC Decision, 22 DOMSC at 238-239. The Siting Council, however, did note that it would have been beneficial for EEC to have provided an evaluation of the relative probabilities of these contingencies. Id. Nevertheless, the Siting Council found that EEC's analysis established that New England would need additional energy resources in an amount at least equal to the proposed project's output for reliability purposes. Id., 22 DOMSC at 241.

In its analysis of the Massachusetts benefits from the proposed project, the Siting Council found that the two signed and approved PPAs with Commonwealth Electric Company and Cambridge Electric Light Company for a combined total of 83 MW established that the proposed project offered reliability and economic efficiency to Massachusetts consistent with the Siting Council's precedent. Id., 22 DOMSC at 243.[259] In addition, the Siting Council found that the proposed project would provide economic benefits to Massachusetts through its steam sales, and additional economic benefits to the local New Bedford area and Massachusetts through the creation of jobs and tax revenues.[260] Id., 22 DOMSC at 248, 250. Finally, the Siting Council found that the proposed project would offer reliability benefits to Massachusetts as a result of its effects on the bulk power transmission system in southeastern Massachusetts. Id., 22 DOMSC at 260-261. In conclusion, the Siting Council found that the benefits to Massachusetts from the proposed project were of sufficient magnitude to offset the impacts on the Commonwealth's resources from construction and operation of the proposed project. Id., 22 DOMSC at 266.

As noted above, the Siting Council has recognized that need may be established on a regional basis on either reliability or economic efficiency grounds. In the above cases,

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259 EEC had provided an analysis of Massachusetts' need for additional energy resources in its original petition as part of its argument that Massachusetts would benefit from the proposed project. EEC Decision, 22 DOMSC at n.48. As the Siting Council had always evaluated Massachusetts benefits based on signed and approved PPAs on addition to other economic or environmental benefits to the Commonwealth rather than the potential for power sales within the Commonwealth, the Siting Council did not evaluate that analysis. Id.

260 The Court noted that the Siting Council is not empowered to elevate economic development benefits above over a balancing of minimum environmental impact and lowest possible cost. City of New Bedford, 413 Mass. at 489-490. As discussed in Section II.C.2.d, below, the Siting Board acknowledges that jobs and tax revenue do not constitute cost or environmental benefits relative to the energy supply of the Commonwealth and, as such, should not be considered in determining need for a proposed project. However, the Siting Board recognizes that economic benefits associated with the development of new projects may be evidence of consistency with "current health, environmental protection and resource use and development policies as adopted by the Commonwealth" as required by G.L. c. 164, § 69J.

although some of the applicants had sought to show a need for their proposed projects on the basis of economic efficiency, the Siting Council consistently found the economic efficiency analyses provided by the applicants to be inconclusive. In the Enron Decision, in addition to an analysis of regional need on reliability grounds consistent with analyses of previous projects, the Company presented an economic efficiency need analysis which addressed many of the concerns raised by the Siting Council in previous reviews of non-utility projects. Based on its review, the Siting Council noted that Enron had presented an acceptable methodological approach to assessing the regional need for additional energy resources based on such economic efficiency grounds. 23 DOMSC at 59-60. Accordingly, the Siting Council found that Enron had established that New England would need additional energy resources in an amount at least equal to the output of the proposed project for economic efficiency in addition to reliability purposes. Id., 23 DOMSC at 62-65. In reviewing need for a proposed non-utility project on economic efficiency grounds, however, the Siting Council noted that " any economic efficiency gains that may result from a particular project, because of their project-specific nature, cannot be viewed in a vacuum; rather, they must be viewed within the context of other attributes of the project." Id., 23 DOMSC at 59. Further, the Siting Board stated that it would have to evaluate, on a case by case basis, whether the magnitude and timing of the economic efficiency gains identified would be adequate to establish regional need on economic efficiency grounds. Id.

Turning to the benefits to Massachusetts that would accrue from the proposed Enron project, the Siting Council found that the existence of a signed and FERC approved PPA with the New England Power Company ("NEPCo") would likely provide the ratepayers of the MECo, a Massachusetts affiliate of NEPCo, with economic efficiency and reliability benefits from the additional power resources. Id., 23 DOMSC at 64-65. In addition, the Siting Council found that other economic benefits would flow to the town in which the proposed project was to be constructed, and to the Commonwealth, through jobs, tax revenues, a lump sum payment, and revenues from the sale of the town's wastewater effluent to the proposed project. Id., 23 DOMSC at 66. Finally, the Siting Council found that Enron had established that the operation of its proposed project would provide Massachusetts with environmental benefits relating to air quality as a result of the displacement of emissions from other electricity generation facilities in the Commonwealth. Id., 23 DOMSC at 69-73. In conclusion, the Siting Council found that the Enron project would provide benefits to the Commonwealth of sufficient magnitude to offset the impacts on the Commonwealth's resources from construction and operation of the proposed project. Id., 23 DOMSC at 74.

The Siting Council developed its approach to the analysis of need for proposed non-utility projects based on its review of its earlier cases relative to utility forecasts and proposals to construct energy facilities. The Siting Council reviewed need with the understanding that the Commonwealth's electric system was a part of the interconnected electric system which serves the entire New England region, an understanding that was inherent in the Siting Council's enabling legislation, and which has been supported by later legislative action (see Section I.B, above). The Siting Council realized that power generation projects proposed for construction in Massachusetts may provide benefits outside the Commonwealth, but that similar benefits would be provided to Massachusetts by power generation projects proposed for construction in neighboring states. As such, the Siting Council determined that, although need for additional energy resources may be based on reliability or economic efficiency reasons, since the directive of the Siting Council's enabling statute speaks to the Commonwealth's energy supply, it is necessary for a proponent to establish the relationship of those reliability or economic efficiency needs to Massachusetts.

For projects with signed and approved PPAs with Massachusetts electric utilities, a showing of such reliability and/or economic efficiency benefits derives from the existence of the PPAs. For projects that seek to be permitted prior to the negotiation of PPAs, a situation that is commonplace and consistent with the rationale behind the Siting Commission's requirement of advance notice of plans to construct power generating facilities, the Siting Council devised its Massachusetts benefits test whereby non-utility developers can establish that other benefits will be realized by the Commonwealth. As a result, the Siting Council required that non-utility developers establish that there is a need for additional energy resources in the region in an amount at least comparable to the output of the proposed project, and that benefits from a proposed project, in terms of power sales or other economic or environmental benefits, must accrue to Massachusetts in sufficient magnitude to offset any impacts from the proposed project.

2. Standard of Review after City of New Bedford

a. The Court's Directive

In the EEC Decision, the Siting Council found that "New England needs at least 300 MW of additional energy resources for reliability purposes beginning in 1995 and beyond. 22 DOMSC at 267. In City of New Bedford, the Court found this finding to be inadequate. 413 Mass. at 489. The Court emphasized that G.L. c. 164 mandates a finding that an energy supply must be necessary for the Commonwealth.[261]

The Siting Board here notes that the Court did not remand the EEC Decision to the Siting Council on this basis. Nevertheless, the Court did raise this as one issue which might arise on remand. Further, the Court noted that the Siting Council had argued that its mandate was to ensure an adequate energy supply at minimum cost. 413 Mass. at 490. The Court stated, however, that "[e]nsuring an adequate supply is not the same as 'provid[ing] a *necessary* energy supply for the commonwealth' (emphasis added)." The Court, however, provided no further guidance on this issue. As the Siting Board reopened the record on the issue of need for purposes of basing the decision on remand on the most current information, the Siting Board must address these two statements of the Court in order to ensure that our standard of review comports with the statutory mandate.

b. A "Necessary" Energy Supply

In regard to the issue of an adequate versus a necessary energy supply, the Siting Board notes that in the Third Report, the Siting Commission also considered this same issue, and "opted for the phrase 'necessary power supply' instead of 'adequate power supply' because of the different connotations and legal ramifications involved." Third Report at 18. The Siting Commission "concluded that the interests of the consumer were more fully protected by the use of the word 'necessary'." Id. Unfortunately, the Siting Commission

[261] In the remand proceedings, the Company provided both a regional and Massachusetts need analysis. The Siting Board reviews these analyses in Sections II.C.4 & 5, below.

also provided no other guidance as to the different "connotations and legal ramifications" of the word necessary. The Siting Council, therefore, was required to determine what was meant by the term "necessary" as it relates to the terms energy supply and power supply contained in sections 69I and 69J.

In a review of possible definitions of the terms, the Siting Board notes that necessary is a word which "must be considered in the connection in which it is used, as it is a word susceptible of various meanings. It may import absolute physical necessity or inevitability, or it may import that which is only convenient." Black's Law Dictionary 928 (5th ed. 1979), citing, Kay County Excise Board v. Atchison, T. & S. F. R. Co., 185 Okl. 327, 91 P.2d 1087, 1088. Webster's New World Dictionary 950 (2d College Ed. 1976) defines necessary as "that that cannot be dispensed with; essential; indispensable."

Adequate, on the other hand, is defined as "[s]ufficient; commensurate; equally efficient; equal to what is required; suitable to the case or occasion; satisfactory." Black's Law Dictionary 36 (5th ed. 1979). Webster's New World Dictionary 16 (2d College Ed. 1976) defines it as either "1. enough or good enough for what is required or needed; sufficient; suitable," or " 2. barely satisfactory."

A review of later actions of the Legislature and Siting Commission, further, blurs the issue. Chapter 110 of the Resolves of 1973 increased the membership and scope of the Siting Commission and directed the Siting Commission to "consider the total energy picture in Massachusetts ... in regards to ensuring that the commonwealth has a sufficient supply of energy for the future" (emphasis added). In addition, the Third, Fourth, and Fifth Reports of the Siting Commission all note that the purpose of the Siting Council is to ensure a sufficient supply of energy for the future while land, air, and water resources are preserved and protected. As noted in the definitions above, sufficient is a synonym for adequate.

A further review of the definition of the term sufficient, reveals that it means "as much as is needed; equal to what is specified or required; enough." Webster's New World Dictionary 1423 (2d College Ed. 1976). Black's Law Dictionary 1285 (5th ed. 1979) notes that sufficient means "adequate, enough, [or] as much as may be necessary" (emphasis added). Thus, the dictionary definitions provide no real guidance either.

The key to the Siting Commission's directive seems to be in the terms "connotations" and protection of the "interests of the consumer." The interests of the consumer would be to have electric energy in ample quantities to meet whatever consumer needs existed, yet still provide least-cost, least-environmental-impact power. A necessary energy supply is one that would be capable of meeting demand in situations that are likely to occur. Thus, a necessary energy supply would be capable of meeting forecasted peak-day demand and would include a (reserve) margin to account for the likelihood of power generating facilities not being available (either planned or un-planned) on those peak days. Operational plans incorporating these factors which relate to capacity supply are commonly used by utilities and regional planning pools such as NEPOOL and have historically served as the basis for the Siting Council's review of long-range forecasts and facility reviews.

In addition, the nature of electric power supply requires a transmission system to distribute the electricity from the power generation units to electric consumers. As transmission systems are not 100 percent efficient in transporting electricity, additional amounts of electric power are necessary to account for these losses, losses that can increase as the distance between the power generation site and its end-use increases.[262] Therefore, to provide for the interests of consumers, any definition of necessary energy supply should allow for consideration of these transmission factors.

Further, as G.L. c. 164 requires a necessary energy supply to be provided with a minimum impact on the environment at the lowest possible cost, it is reasonable to conclude that a proposed facility may be necessary even if there is no additional need for supply capacity or transmission reasons. In such a case, an applicant would have to establish a record that supported a finding by the Siting Board that the Commonwealth's energy supply would have lower costs and/or reduced environmental impacts with the addition of the

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[262] Transmission systems also have certain physical limits such that the transmission system becomes unstable if the reactive power is inadequate. In the EEC Decision, the Company indicated that reactive power is needed to maintain voltage levels and the stability of the transmission grid and to supply inductive loads to motors, transformers and air conditioning systems. 22 DOMSC at n.63. The Company also indicated that generating facilities are possible sources of reactive power. Id..

proposed facility than it would have without the addition of the proposed facility.[263,264] Accordingly, based on the foregoing, the Siting Board finds it appropriate, without more specific guidance regarding the definitions of necessary and adequate, to adopt the Siting Council's past approaches to determining whether the addition of a proposed facility to the energy supply is necessary in this and future decisions.

In the EEC Decision, the Siting Council reviewed its precedent relative to what constituted a necessary energy supply. 22 DOMSC at 203-205. The Siting Council noted that need has been found: (1) where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements; (2) in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs; or (3) principally for providing economic energy supplies relative to a system without the proposed facility.[265] The Siting Council did not alter its approach in the

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263 In allowing applicants to independently establish project need based on considerations other than a capacity deficiency, the Siting Board recognizes that such need may affect part or all of a projects's proposed size capability and part or all of a project's proposed life. However, the Siting Board also recognizes that, as the Siting Council noted in the Enron Decision, project approval under such circumstances would warrant an additional determination -- that cost, environmental or reliability benefits outweigh the costs and any adverse environmental impacts of the project.

264 The Siting Board notes that the present applicant has made no such argument, nor is such a finding the basis of this decision; however, such a finding would be consistent with G.L. c. 164 which requires the Commonwealth's energy supply to be provided with a minimum impact on the environment at the lowest possible cost.

265 The Siting Board notes that in reviews of need for new energy resources, the Siting Council, consistent with G.L. c. 164, § 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in NEPOOL, interpreted its mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources, but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. See, MASSPOWER Decision, 20 DOMSC at 311-323; Altresco Decision, 18 DOMSC at 151-281; NEA Decision, 16 DOMSC at 344-360; Massachusetts Electric Company/New England Power Company, 15 DOMSC 241, 273, 281 (1986).

EEC Decision. The finding of need for additional energy resources in that decision comports with both the first and second of these three approaches.[266]

c. The Commonwealth's Need for Additional Energy Resources

i. Arguments of the Parties

(A) The Company's Position

EEC stated that in previous evaluations of petitions to construct independent power projects, the Siting Council consistently determined that there is a reliability need for a proposed facility where new capacity provided by the proposed facility would satisfy projected load and reserve requirements above projected levels of capacity on a regional basis (EEC Brief at 5-7). EEC stated that the Court criticized the Siting Council analysis because its determination of need related to the region rather than to Massachusetts but that the Court did not specify a particular methodology for the Siting Board to use to evaluate Massachusetts need (id.).

The Company stated that, consistent with the statutory mandate, there are two reasonable approaches for the Siting Board to use to determine whether the proposed facility is needed based on reliability considerations -- a demonstration of a capacity deficiency for Massachusetts or a demonstration of a capacity deficiency on a regional basis (id. at 8-9). The Company asserted that, where a capacity deficiency is demonstrated for Massachusetts based on an analysis of the projected electricity demand within the Commonwealth and the supply resources committed to meet that demand, the clear language of the statute would require the Siting Board to find that a proposed facility is needed to provide a necessary energy supply for the Commonwealth (id. at 8). The Company defined Massachusetts supply in terms of Massachusetts' electric utilities' contractual entitlements to capacity from

266 The Siting Board notes that the Legislative enactments that have upheld the agency's decisional precedent would appear to be a statement that the Legislature considers the Siting Council to have provided proper connotations to the term necessary as it relates to the energy supply. Reorganization Act, § 46; Acts of 1990, c. 150, § 326A.

facilities regardless of their location (id. at 31).[267] The Company stated that reliance on an approach based on contractual entitlements would acknowledge the ability of Massachusetts utilities to import and export power across state lines through participation in NEPOOL (id. at 32). EEC stated that this approach would be realistic and conservative in assessing the state's need for new capacity (id.).

In the alternative, the Company asserted that the Siting Board can find need for a proposed facility where a deficiency is demonstrated on a regional basis, provided that the Siting Board provides a statement of the benefits that Massachusetts receives from NEPOOL membership (id. at 9; EEC Reply Brief at n.6). EEC stated that, given the integrated regional electricity system and tangible benefits to Massachusetts resulting from participation in the NEPOOL system, it would be consistent with the statute to base need for a proposed facility on regional considerations (EEC Brief at 12-13).[268] However, EEC added that the existence of a regional surplus when there is a capacity deficiency in Massachusetts would not necessarily preclude a finding of Massachusetts need (EEC Reply Brief at 6-10). Instead, EEC stated that any regional surplus should be considered a potential supply option to meet an identified Massachusetts need (id.).[269]

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267 The Company stated that an alternative definition of Massachusetts supply would identify supplies based on the physical location of generation within the state's geographic borders (EEC Brief at 31).

268 EEC asserted that the inextricable link between regional and Massachusetts' reliability and the appropriateness of a regional need analysis was recognized by the Legislature in establishing the Siting Council (EEC Brief at 9-10). EEC asserted that the appropriateness of a regional analysis was also confirmed by G.L. c. 164A, the intent of which is to foster participation of electric utilities in NEPOOL (id. at 11).

269 EEC stated that, because of (1) constraints on the transmission system; (2) NEPOOL restrictions; and (3) reliability and cost considerations, a finding of regional surplus capacity would not necessarily indicate that a regional capacity surplus would be available to meet a Massachusetts need (EEC Reply Brief at 7).

In addition, the Company stated that, although the Court was silent on the appropriateness of using economic efficiency[270] as an independent basis to demonstrate need, an economic efficiency analysis also would be consistent with the Siting Board's obligation to ensure a necessary energy supply at the lowest possible cost with a minimum impact on the environment (EEC Brief at 13). Therefore, the Company asserted that a demonstration that a proposed facility would result in lower costs for the Commonwealth's ratepayers would be sufficient to establish need (id.). EEC further asserted that a regional economic efficiency analysis also would demonstrate Massachusetts' economic efficiency benefits (id. at 13-14). The Company explained that due to the integrated nature of the NEPOOL system, Massachusetts would share in the economic efficiency savings of a facility, even if the power were sold to a utility outside Massachusetts (id. at 14).

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

(B) The Attorney General's Position

The Attorney General argued that the criteria for demonstrating Massachusetts need must reconcile the language of the statute and the Court's decision in City of New Bedford with the integrated nature of the Massachusetts and regional electricity system through

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270 The Company noted that in the Enron Decision, the Siting Council found that economic efficiency can establish need if the addition of the proposed new facility would result in lower generation costs for the system than would be experienced without the new facility (EEC Brief at 13).

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

participation in NEPOOL (Attorney General Brief at 5). He stated that, in the absence of PPAs, determination of need should begin with an analysis of regional capacity (id.). He argued that demonstration of a regional capacity surplus should compel a finding that the proposed facility was not needed while demonstration of a regional deficiency would require a further showing of reliability benefits to the Massachusetts electricity system (id. at 5-6). He further argued that the Siting Council consistently has held that reliability benefits to Massachusetts may be demonstrated only through the existence of signed and approved PPAs with Massachusetts utilities (id. at 10).[271]

ii. Analysis

In City of New Bedford, the Court stated that our statutory mandate is to ensure that a necessary energy supply is provided for the Commonwealth and stated that a finding of regional need is inadequate as the sole foundation of a finding of need for additional energy resources for the Commonwealth. Nevertheless, given the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability, and recognizing the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration, the Siting Board agrees with both the Company and the Attorney General that consideration of regional need is a central part of any need analysis for a power project not yet linked to individual utilities by PPAs.

The Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A. This same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3,4. This need for regional cooperation was also noted in the Siting Commission's Third Report. See n.34, above. In

271 The Company responded that although the existence of such contracts would be an alternative method of establishing Massachusetts need, such contracts should not be the sole determinant of Massachusetts need (EEC Reply Brief at n.7). The Company asserted that the Court has recognized that entering into contracts can occur after Siting Board approval (id.). Further, any attempt to require the output from a facility to be sold to Massachusetts utilities would conflict with NEPOOL operation (id. at 7).

fact, in enacting the Siting Council's enabling legislation, the Legislature accepted the recommendation of the Siting Commission -- that the importance of regional planning to ensure reliability as well as minimize cost to the electric industry and consumers should not be lost in the facility siting process in Massachusetts. A review of need that is limited to the need in the Commonwealth for new energy resources would require the construct of an electric energy market that was limited by state borders and would appear to be contrary to legislative intent.

Further, few, if any, Massachusetts electric utilities produce all of their own electric power requirements. Electric utilities purchase power from other electric utilities as well as from non-utility generators in the New England region. Such purchases provide increased reliability to the electric utility's system. This increased reliability is achieved by purchasing electric power from facilities that use a diverse source of fuel, thereby reducing impacts from fuel-related shortages or other constraints on the supply of any one fuel, and by purchasing power from numerous electric power facilities for a portion of the utility's needs, thereby reducing impacts from planned or unplanned outages at those facilities. The existence of PPAs with both foreign and domestic electric companies, therefore, assists in providing a necessary energy supply for the Commonwealth which is both reliable and least cost. As such, the Siting Board finds that an analysis of regional need must form the foundation for any analysis of Massachusetts need.

In previous evaluations of petitions to construct non-utility power projects, the Siting Council consistently held that a demonstration of regional need alone, however, would be insufficient to establish need for the additional energy resources. Therefore, in addition to a demonstration of regional need, the Siting Council required a demonstration of Massachusetts need. Specifically, the Siting Council required a proponent to establish that Massachusetts is likely to receive reliability, economic efficiency or other benefits from the proposed energy facility in sufficient magnitude to offset the construction and operation of such facility in the state. See Section II.C.1., above. The Siting Board finds 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.

The Siting Board recognizes, however, that over the course of the Siting Council's reviews, the definition of Massachusetts benefits which could contribute to a showing of Massachusetts need was expanded to encompass benefits that do not relate directly to the Massachusetts energy supply. See, e.g., Enron Decision, 23 DOMSC at 65-66; EEC Decision, 22 DOMSC at 249-250. In response to the Court's reminder that our statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board finds that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need.[272]

Here, both the Attorney General and the Company have argued that a Massachusetts capacity analysis should be considered to establish Massachusetts need.[273] EEC argues that a showing of a Massachusetts capacity deficiency or a regional capacity deficiency should be sufficient, on its own, to establish need for a proposed facility, while a showing of a regional capacity surplus would not, on its own, demonstrate that a proposed facility was not needed. The Attorney General, on the other hand, argues that a showing of a Massachusetts capacity deficiency would not be sufficient, on its own, to establish need for a proposed facility while

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

[273] The Siting Board notes that in previous reviews of petitions to construct non-utility power projects, the Siting Council did not review analyses of Massachusetts capacity.

a showing of a regional capacity surplus would be sufficient to establish that a proposed facility was not needed, without further consideration of Massachusetts need.[274]

As noted above, the Siting Board recognizes that a regional capacity analysis provides a foundation for, rather than the sole determinant of, a finding of need. Contrary to the Company's argument above, therefore, neither a regional capacity deficiency, taken alone, nor a Massachusetts capacity deficiency, taken alone, would be sufficient to establish need.[275] Similarly, with regard to a showing of a regional capacity surplus, the Siting Board disagrees with the Attorney General that such a showing, by itself, would establish that a proposed facility was not needed for Massachusetts. For example, an applicant might provide evidence that reliance on a regional surplus to address or offset a Massachusetts supply deficiency would involve transmission or other reliability constraints. In addition, as noted above, an applicant might establish that reliance on a regional capacity surplus would be contrary to the statutory mandate to ensure that a necessary energy supply is provided for the Commonwealth at the lowest possible cost with least environmental impact. Thus, the Siting Board finds that the demonstration of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply.

The Attorney General correctly states that in past decisions the Siting Council found that signed and approved PPAs with Massachusetts utilities demonstrate Massachusetts need. The Siting Council held (1) that a signed and approved PPA between a QF and a utility

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274 In considering Massachusetts supply within an analysis of Massachusetts need, the Siting Board agrees with EEC and the Attorney General that Massachusetts supply should be based on Massachusetts' utility entitlements rather than physical location of power generation facilities within the state.

275 The Siting Board notes that there is no guarantee that a proposed project without PPAs with Massachusetts utilities will sell its power in Massachusetts. Therefore, a Massachusetts need analysis alone does not guarantee that the power and other benefits of a proposed project will go to Massachusetts. The Siting Board notes that this was the original reason for requiring both a regional need analysis and a Massachusetts need analysis.

constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes prima facie evidence of the need for additional energy resources for reliability purposes. See, e.g., NEA Decision, 16 DOMSC at 358. However, the Siting Board notes that the Attorney General is mistaken in stating that the Siting Council consistently held that Massachusetts need only could be demonstrated through the existence of signed PPAs with Massachusetts utilities. Rather, in previous evaluations of petitions to construct non-utility power projects, the Siting Council accepted other means of demonstrating Massachusetts need. See Section II.C.1, above. Thus, 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. 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.

Finally, the Siting Board agrees with the Company that a facility located in Massachusetts should not be required to sell all of its output to Massachusetts utilities. Such a requirement would conflict with (1) the regional operation of NEPOOL, thereby potentially decreasing the reliability of the regional electric power market, and (2) the apparent intent of the NEPOOL legislation which authorizes foreign and domestic utilities to build facilities in Massachusetts and sell power out of state.

d. Findings and Conclusions

In Section II.C.2.d., above, the Siting Board has made the following subsidiary findings:

- an analysis of regional need must form the foundation for any analysis of Massachusetts need (p. 186);
- 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 (pp. 186-187);

- reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth to be considered in support of a finding of Massachusetts need (p. 187);
- the demonstration of a regional capacity surplus would be insufficient by itself to establish that a proposed facility was not necessary for the Commonwealth's energy supply (p. 188);
- 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 (p. 189); and
- 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 (p. 189).

In conclusion, in accordance with G.L. c. 164, sec. 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 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 to meet reliability, economic, or environmental objectives directly related to the energy supply of the Commonwealth. The Siting Board therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board may find that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements.[276] With regard to contingencies, the Siting Board may find that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that service to firm customers can be maintained in the event that a reasonably likely contingency occurs.[277] The Siting Board also may determine in some instances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. See Section II.C.2.b., above.

While G.L. c. 164, sec. 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,[278] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs.[279] In doing so, the Siting Board fulfills the requirements of G.L. c. 164, sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in NEPOOL.

In cases where a non-utility developer seeks to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board requires the

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[276] See, Altresco Decision, 17 DOMSC at 360-369; NEA Decision, 16 DOMSC at 344-360; Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); New England Electric System, 2 DOMSC 1, 9 (1977).

[277] See, Middleborough Gas and Electric Department, 17 DOMSC 197, 216-219 (1988); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

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

[279] See, Turners Falls Limited Partnership, 18 DOMSC 141, 151-165 (1988); Altresco Decision, 17 DOMSC at 359-365; NEA Decision, 16 DOMSC at 344-360; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); Massachusetts Electric Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985).

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 PPA's. 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.

3. New England's Need

a. Introduction

EEC asserted that there is a need for new capacity in New England beginning in the year 1997 and beyond (EEC Brief at 54-57). In support, the Company presented a series of forecasts of demand and supply for the region, based in part on data and 1992 forecasts published by NEPOOL. The Company stated that it combined its demand and supply forecasts to produce a series of need forecasts and then subjected its need forecasts to a variety of contingency tests to evaluate the sensitivity of the need projections to the uncertainty inherent in the underlying forecast assumptions (Exhs. HO-RN-11(u), HO-RN-13A(u), HO-RN-13B(u), HO-RN-13C(u), HO-RN-14B(u)).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts, which are based on a comparison of the various demand and supply forecasts, and the contingency cases which combine the contingency tests with the need forecasts.

b. Demand Forecasts

i. Description

The Company presented nine demand forecasts of adjusted peak load demand (Exh. HO-RN-23, att.). The Company stated that it based its demand forecasts on three different demand forecast methodologies and adjusted results from each of the demand forecast methodologies to reflect three different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id.).

(A) Demand Forecast Methodologies

The Company stated that it developed its demand forecasts based on the following three methodologies: (1) the 1992 CELT Report Reference Forecast ("reference forecast"); (2) the expected value forecast prepared by NEPOOL and presented in its 1992 Resource Adequacy Assessment ("expected value forecast"); and (3) the relationship between historic peak demand and growth in the Gross Domestic Product ("GDP") ("GDP forecast") (id.). The Company indicated that two of its three forecast methodologies -- the reference forecast and the expected value forecast -- are common to both the regional need analysis and the Massachusetts need analysis (Exh. HO-RR-137).[280]

To develop the reference forecast, the Company explained that NEPOOL produced (1) a short-term forecast for the years 1992 and 1993 based on an econometric model, and (2) a long-term forecast for the years 1996 through 2007 based on an end-use model, and then merged the short-term and long-term forecasts to produce projections for the years 1994 and 1995 (Exh. HO-RN-23, at 9-10).[281] EEC indicated that NEPOOL also produced two alternative forecasts of future regional peak demand as part of the 1992 CELT report -- a high demand forecast and a low demand forecast -- which are based on different sets of economic assumptions (id. at 2-6).[282]

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280 The Company used these two "common-case" forecasts to assess the relative timing of need in the Massachusetts need analysis, as compared to that in the regional need analysis (see section , below).

281 Mr. La Capra stated that NEPOOL did not specify how the short-term and long-term model results were merged (Exh. HO-RN-23, att. at 9-10).

282 EEC indicated that NEPOOL characterizes: (1) the high demand case as having a 10 percent probability of being exceeded; (2) the reference case as having a 50 percent probability of being exceeded; and (3) the low demand case as having a 90 percent chance of being exceeded (Exh. HO-RN-1, n.1). EEC further indicated that the (continued...)

EEC stated that, in general, it regards the reference forecast as reasonable in the long run (Exh. HO-MN-44). However, the Company stated that the reference forecast projects adjusted peak load at lower than NEPOOL's 1991 weather-normalized summer peak of 19,700 MW in the near term, and that it will not return to that level until 1994 (id. at 7-8).[283] EEC characterized the reference forecast overall as representing a "low band" of reasonably expected regional demand in that it is overly pessimistic, particularly in the near term (id.).[284]

In explaining his concerns with the short-term results of the reference forecast, Mr. La Capra testified that NEPOOL's short-term forecast was based on forecasts of three exogenous variables -- personal income, number of residential customers and real residential energy prices (id. at 10). He asserted that the short-term forecast was overly pessimistic

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[282](...continued)
reference case is closer to the low demand case than the high demand case (Exh. HO-RN-23, att. at 6). EEC noted that this asymmetry indicates that there is more uncertainty and potential for error surrounding the growth in demand on the high side than there is on the low side (id.).

[283] Mr. La Capra stated that he regarded the high demand forecast as a reasonable high demand case (Exh. HO-RN-23, at 6-7). He explained that the high demand forecast anticipates a spurt in the demand for electricity over the 1992-1997 period based on a robust recovery of the regional economy, consistent with historical recoveries, but noted that, due to current predictions for a modest recovery, the high demand forecast likely was optimistic in the short run (id. at 7). In addition, Mr. La Capra stated that the low demand forecast, which is significantly more pessimistic than the 1991 CELT forecast, would have a probability of occurrence of essentially zero (id.). He explained that the low demand forecast predicts a significant decline in peak demand in 1992 and that it would remain below the NEPOOL 1991 weather-normalized summer peak until the year 2000 (id. at 8). He stated that such a decline in peak demand is unprecedented and unsupported by evidence, indicating that an economic recovery is currently underway (id. at 8-9).

[284] EEC indicated that the reference forecast adjusted by the 1992 CELT values for DSM reflects a compound annual growth rate ("CAGR") in adjusted peak load of 1.9 percent over the forecast period (Exh. HO-RN-23, att. at 3).

because (1) the economic trends reflected were overly pessimistic,[285] and (2) fuel price projections, primary drivers of real electricity prices, were unrealistically high (id. at 13-16).[286] He further stated that the dampening effect on demand caused by the use of such high fuel price assumptions would carry beyond 1994 in that annual fuel price projections are compounded over time (id. at 15). In addition, Mr. La Capra questioned the overall objectivity and reliability of the short-term forecast because NEPOOL made ad hoc adjustments to data developed by its own consultants and did not rely solely on objective economic and fuel price forecasts (id. at 10-16; Tr. JH4, at 35-36).[287]

With regard to the expected value forecast, EEC first defined the expected value as the mean value of a probability distribution, or the weighted average of all possible outcomes in the distribution (Exh. HO-71; Tr. JH5 at 60-61). Mr. La Capra explained that the 1992 NEPOOL Resource Adequacy Assessment, Technical Supplement ("Resource Assessment") provides a probability distribution for the variation in expected regional load growth assumed by NEPOOL for the years 1993 through 1997,[288] and from this distribution, provides the

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285 Mr. La Capra stated that economic data indicating that an economic recovery is underway in New England contradicts NEPOOL's assumption that an economic recovery would not begin in New England until the fourth quarter of 1992 (Exh. HO-RN-23, att. at 13).

286 Mr. La Capra stated that NEPOOL's forecast of higher real electricity prices in 1992 and 1993 was driven primarily by high short-term fuel price projections (Exh. HO-RN-23, at 13). He stated that NEPOOL made upward adjustments to an objective forecast of 1992 fuel prices and noted that, in addition, NEPOOL's price forecast for residual oil was higher than two other price forecasts (id. at 14).

287 Mr. La Capra stated that one modification made by NEPOOL was to adjust the personal income forecast for 1992 downward from an objective forecast of personal income (Exh. HO-RN-23, att. at 11). In addition, Mr. La Capra indicated that NEPOOL relied on a modified Delphi method, or opinion poll of members of its Load Forecasting Committee, to forecast the variables underlying the short-term forecast (id. at 10). He stated that this approach is a highly subjective means for producing a forecast and inappropriate where quantitative forecasts are available (id. at 10-11).

288 EEC indicated that the five drivers to the 1993-1997 load growth forecast were (continued...)

expected value of the load forecast for each year from 1993 through 1997 (Exh. HO-RN-23).[289] EEC indicated that the probability that actual load would be less than or equal to the load predicted by the expected value forecast, that is, the confidence level of the forecast, would vary between 57 percent and 62 percent for the years 1993 through 1997 (Exh. HO-JH-RR-8).[290] The Company extrapolated values for the years beyond 1997 based on a linear regression of the NEPOOL forecast data for 1993 through 1997 (id.).[291]

EEC stated that the expected value forecast would represent a reasonable base-case demand forecast (Exh. HO-RN-23). The Company maintained that a probabilistic forecast of demand, i.e., the expected value forecast, would be preferable to a deterministic forecast, i.e., the reference forecast, because "probabilistic forecast methodology is better able to

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[288](...continued)
employment, economic output, population, and real prices of electricity and fuels (Tr. JH5, at 53; Exh. HO-71, at 6).

[289] The Company indicated that the expected value exceeded the reference forecast by: (1) 180 MW in 1993; (2) 394 MW in 1994; (3) 678 MW in 1995; (4) 664 MW in 1996; and 886 MW in 1997 (Exh. HO-RN-26, att. 2 at 56-60; Tr. JH5, at 40-41).

[290] Mr. La Capra explained that the expected value forecast would differ from the 50 percent confidence level, which is the basis for the reference forecast, in that the 50 percent confidence level represents a median while the expected value represents the average of a range of outcomes weighted by the probability of occurrence (Tr. JH5, at 61-62). He further explained that the expected value would not equal the 50 percent level where the likely margin of potential error is higher on one side of the median than the other (id. at 63-64). He noted that the expected value forecast demonstrates that there is a higher probability of error on the deficiency side than on the surplus side (id. at 65-66). Mr. La Capra added that, given the magnitude of uncertainty in need, the potential consequences of supply shortages and the long lead times required to develop new resources, a confidence level of 60 to 70 percent is more reasonable than a 50 percent confidence level for supply planning purposes (Exh. HO-MN-43).

[291] EEC noted that, as an alternative to the linear regression approach, it considered applying the 1992 CELT report annual percentage change to the years 1998 and beyond (Exh. HO-RN-31). EEC stated that the linear regression is conservative in that demand values for 1998 and 1999 were slightly less than the corresponding values derived from the CELT percentage change (id.).

predict the potential impacts of the significant uncertainties which affect the timing and magnitude of the need for new resources" (Exh. HO-MN-43).

Finally, EEC indicated that the GDP forecast reflects current economic conditions in that it compares the growth in peak load to the growth in GDP -- a measure of all output within the geographic confines of the United States (Exh. HO-RN-23).[292] The Company stated that the historical trends in normalized summer peak load in New England and GDP show an essentially one-to-one relationship (id.).[293,294] EEC indicated that it assumed growth in GDP would be: (1) 1.7 percent for the years 1991 and 1992;[295] (2) three percent for the years 1993 through 1995; and (3) 2.5 percent for the remaining forecast years (id.).[296] The Company classified the GDP forecast as a moderate-to-high demand forecast (id.). Mr. La Capra asserted that the GDP forecast would accurately account for the impact of future utility-sponsored DSM programs if DSM program levels did not increase substantially, in absolute terms, over the forecast period (Tr. JH5, at 87-89).

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292 EEC indicated that a demand forecast based on the Gross National Product ("GNP") was included in the original petition (Exh. HO-RN-23). The Company stated that since that time, the United States government changed its primary measure of economic activity from "GNP," which is a measure of all output of United States-owned firms regardless of location, to the GDP (Exh. HO-RN-23).

293 EEC forecast peak loads using GNP data for 1974 through 1991 and 1974 through 1985 (Exhs. HO-RN-29, HO-RR-133). The relationship between GNP and peak load was 1:1 for the 1974 through 1985 period and 1.1:1 for the 1974 through 1991 period (id.).

294 Mr. La Capra indicated that personal income growth is another measure of economic activity that has a strong correlation with electricity demand (Tr. 28, at 4). He noted that the forecast was based on the GDP rather than personal income because GDP forecasts were available for a longer period and because GDP is a more inclusive measure (id.).

295 The Company indicated that the actual 1992 annual growth figure, available at the time of the hearings, was 2.1 percent (Tr. JH5, at 19).

296 The Company indicated that it based its forecast of the GDP on a number of forecasts of the GDP including the forecast included in the 1992 "Economic Report of the President" (Exh. HO-AG-RR-62).

(B) DSM

EEC indicated that, in order to incorporate DSM savings from utility-sponsored programs into the CELT forecast, NEPOOL first projects DSM savings over the forecast period by aggregating the DSM forecasts of the individual utilities (Tr. 23, at 7). EEC stated that NEPOOL then deducts its projection of DSM savings from the load forecasts derived from its short-run and long-run load forecasting models (Exhs. HO-72 at 1-1; HO-RN-36).

However, Mr. La Capra asserted that NEPOOL projections of DSM savings likely overestimate the savings that the region will actually experience as a result of utility-sponsored programs (Exh. HO-RN-23, att. at 17). In support, he stated that in previous CELT forecasts NEPOOL consistently has overestimated the contribution of DSM resources to peak demand reduction (id.). Specifically, he stated that since 1988, actual DSM savings, on average, have been approximately 18 percent less than the DSM forecast by NEPOOL (id. at 17, att. RLC(2)).[297] He explained that NEPOOL's overforecast primarily is due to the manner in which individual utilities project savings from existing and planned DSM programs (Exh. HO-RN-23, att. at 17-20). He stated that utility projections are based on engineering estimates, i.e., calculations of the average savings achievable from a particular DSM measure, and that such estimates generally overpredict actual savings as measured by impact evaluations (id.; Tr. JH6, at 9-11).[298]

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297 The Company indicated that an analysis of NEPOOL DSM forecast accuracy indicates that: (1) actual DSM was less than the 1988 forecast of DSM by 3.7 percent for 1988, 8.6 percent for 1989, 6.3 percent for 1990 but was more than the 1988 DSM forecast of DSM by 1.8 percent for 1991; (2) actual DSM was less than the 1989 forecast of DSM by 50.4 percent for 1989, 49.4 percent for 1990, and 35.0 percent for 1991; (3) actual DSM was less than the 1990 forecast of DSM by 12.8 percent for 1990 and 12.0 percent for 1991; and (4) actual DSM was less than the 1991 forecast of DSM by 5.4 percent for 1991 (Exh. HO-RN-23, att. RLC(2)).

298 Mr. La Capra stated that some reasons for overestimates include erroneous assumptions in engineering calculations, unanticipated interactions among DSM measures, technical problems, customer behavior changes and weather variations (Exh. HO-RN-23, att. at 19; Tr. JH6, at 9).

The Company asserted that another reason for NEPOOL overprediction relates to recent changes in the economic and regulatory climate (EEC Brief at 64-66). The Company stated that, after utilities submitted DSM forecasts to NEPOOL, there were reductions in DSM budgets, reductions in load management programs and increased regulatory concerns with rate impacts, which would decrease actual DSM savings below projections (Tr. JH6, at 6-7; Tr. JH1, at 45-47; Tr 23, at 71, 82-83).

EEC stated, therefore, that it would be inappropriate to evaluate regional need for new capacity based on the assumption that 100 percent of the utilities' projected DSM savings would be achieved, and instead, a more realistic DSM scenario should be considered (Exh. HO-RN-23, att. at 20-21). Thus, EEC provided an alternative DSM forecast as a base DSM case which assumed that DSM growth above 1991 levels would be 25 percent less than the growth forecast by NEPOOL (id. at 21; Exh. HO-RN-28).[299]

EEC also provided a high DSM case which assumed the NEPOOL DSM forecast (Exh. HO-RN-28). In addition, EEC provided a low DSM case which discounted DSM growth above 1992 levels by 50 percent (id.). EEC indicated that NEPOOL DSM projections are based largely on engineering estimates which generally have proven to overpredict DSM savings by an average of 30 percent to 50 percent (Exh. HO-RN-23, at 19-20).

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299 Mr. La Capra stated that the 25 percent discount factor for the base DSM case was based on the analysis of NEPOOL DSM forecast accuracy (see n.297, above) (Tr. 23, at 47). He stated that, even though the average forecast error is approximately 18 percent, a 25 percent discount is a better estimate due to the significant range of error in the analysis and uncertainty in the current stage of DSM programs (id. at 47-48). In addition, he stated that the resource assessment indicates that the probability is greater that the NEPOOL DSM forecast will not be achieved than will be achieved, and that the 1992 expected value of DSM was closer to the Company's 75 percent value than the forecast value (id. at 51-53).

The Siting Board notes that, in the Resource Assessment, NEPOOL identified (1) a high DSM case with a 10 percent probability of being exceeded,[300] and (2) a low DSM case with a 90 percent probability of being exceeded (Exh. HO-RN-4(a) at 32).[301,302]

ii. Positions of the Intervenors and Company's Response

(A) Demand Forecasts

The Attorney General argued that the Company's regional demand forecast methodologies overstate likely future load growth (Attorney General Brief at 15-36). The Attorney General's witness, Dr. Shakow, provided alternative testimony relative to: (1) the 1992 CELT forecasting methodology; (2) the Company's development of the expected value and GDP forecasts; and (3) the nature of the current economic recession (Exh. AG-204).

With respect to the reference forecast, the Attorney General argued that this forecast is not representative of a low forecast, but instead, is likely to overstate demand (Attorney General Brief at 23-33). In support, he stated that (1) the economic assumptions of the reference forecast do not adequately reflect the structural impediments and resultant weakness of the economy, and (2) methodological changes employed by NEPOOL had the effect of increasing the unadjusted load forecast of the reference forecast (id.).

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300 In response to a request by the Siting Board, the Company also evaluated need based on NEPOOL's high DSM case (Exh. HO-RR-136). See Section II.C.3.d.i., below. The Siting Board notes that NEPOOL's high DSM case exceeds the Company's high DSM case by: (1) 42 MW in 1997; (2) 56 MW in 1998; (3) 109 MW in 1999; and (4) 166 MW in 2000 (id.; Exh. HO-RN-11(u)).

301 The Siting Board notes also that, for the years 1997 to 2000, the NEPOOL low DSM case exceeds the Company's low DSM case by: (1) 161 MW in 1997; (2) 201 MW in 1998; (3) 232 MW in 1999; and (4) 260 MW in 2000 (Exhs. HO-RN-14B(u); HO-RN-4(a) at 32).

302 The Siting Board further notes that, in the EEC Decision, the Company provided a high DSM case based on the amount of DSM defined in the 1989 resource assessment as having a 10 percent chance of occurring and a low DSM case based on the amount of DSM defined in the 1989 resource assessment as having a 90 percent chance of occurring (22 DOMSC at 224).

In discussing the economic assumptions of the reference forecast, the Attorney General disagreed with Mr. La Capra's conclusion that the economic forecast underlying the reference forecast is overly pessimistic given that an economic recovery is underway (id., citing, Exh. HO-RN-23, att. at 13).[303] Dr. Shakow testified that the projected levels of economic activity driving the reference forecast are instead too high (Exh. AG-204, at 4). He explained that, although the United States economy has experienced a technical recovery since June 1991, the current recession has been protracted and the recovery dampened due to the structural factors affecting the economy, especially in relation to employment (Exhs. AG-204, at 22-30; HO-RR-142; HO-RR-145).[304] He added that the recession would persist in the absence of major shifts in structural impediments to growth (Exh. HO-RR-145).

In addition, the Attorney General asserted that unjustified methodological changes have led to an increase in the unadjusted load forecast of the reference forecast (Exh. AG-204, at 9-18). He stated that such changes include changes to: (1) the forecast of electricity prices; (2) the assumptions regarding new technologies; and (3) estimates of productivity (id.). The Attorney General argued that a predicted decline in electricity prices provided the most significant upward pressure on the reference forecast (Attorney General Brief at 28). Dr. Shakow testified that such decline in the electricity price forecast was due to unjustified

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303 The Attorney General argued that the majority of Mr. La Capra's comments on the reference forecast report pertain to NEPOOL's short-term forecast which ceases to have an effect on NEPOOL's load projections after 1995 (Attorney General Brief at 24, citing Exhs. HO-RN-23, att. at 9-12; AG-204 at 17-18; Tr. 29 at 27-28). Therefore, he argued that the short-term forecast is irrelevant to the Siting Board's determination of need in this case (Attorney General Brief at 24).

304 Dr. Shakow indicated that there are major structural impediments in the United States to robust economic recovery and performance including: (1) debt overhang; (2) decreased prospects for reducing debt burden; (3) scarcity of loanable capital; (4) institutional weakness in the financial and banking sectors; (5) heavy foreign holding of United States debt; (6) declining competitive position of United States industry relative to other industrialized countries; (7) shift away from New England industries; and (8) outmoded and defective infrastructure and capital, including human capital (Exh. AG-204 at 22-30).

methodological changes including (1) a change in the definition of electricity price,[305] and (2) a change in price forecasting methodology (Exh. AG-203, at 13-14).[306]

Relative to the incorporation of new technologies into the reference forecast, Dr. Shakow testified that NEPOOL assumptions of forecasted sales of electric vehicles are inappropriate given uncertainties surrounding their acceptance (id. at 15).[307] Finally, the Attorney General asserted that NEPOOL introduced changes into its model of regional economic activity which led to increased estimates of productivity -- significantly higher than would be expected based on actual growth over the past two decades or current economic conditions (Attorney General Brief at 31, citing, Exhs. HO-72, at 3-1; AG-204, at 11, 15).

With respect to the expected value forecast, the Attorney General argued that said forecast does not provide a reliable basis for determining regional need due to (1) NEPOOL's methodology in deriving the expected value forecast, and (2) EEC's use of the expected value forecast to develop a base case forecast for the overall 1992-2007 period (id. at 15-23).

With regard to NEPOOL methodology, the Attorney General first stated that the forecasted load growth distribution is skewed such that higher loads are more likely to occur

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305 Dr. Shakow explained that in the 1992 CELT report, the traditional rate concept of electricity price was replaced with an "energy services concept" which assumes that a consumer who uses less electricity as a result of the installation of DSM measures would not reduce electricity consumption even further as a result of rate increases (Exh. AG-204, at 10, 14). He added that this definition therefore biases the price downward and the demand forecast upward (id.).

306 Dr. Shakow explained that previously, a computer model, PROSCREEN was utilized to forecast electricity prices but that for the reference forecast, an aggregation of individual utility company forecasts for components of financial revenue requirements was utilized (Exh. AG-204, at 9-10). He stated that the PROSCREEN model accounted for the secondary effects on demand and price of cost-recovery mechanisms while the individual utility forecasts would not take such secondary effects into account, and thus, would bias prices downward (id. at 13-14).

307 Dr. Shakow indicated that the possibility of electric vehicle penetration should have been included as a demand contingency rather than as an element of the base case forecast (Exh. AG-204, at 15).

than lower loads (Attorney General Brief, citing, Exh. HO-71, at 9). He further argued that NEPOOL's methodology for developing the two components of high-side uncertainty -- the peak-load values associated with the high-load forecast and the probability assigned to that forecast -- was unsound (Attorney General Brief at 15-21). Specifically, the Attorney General argued that, in order to develop a high-load forecast, NEPOOL made inappropriate ad hoc adjustments to a rigorously developed economic forecast (id. at 16-18). The Attorney General explained that NEPOOL, in developing its high-load forecast, rejected an optimistic economic forecast prepared by an independent consultant because it was low relative to recoveries from previous recessions (id., citing, Exh. HO-72 at 5-7, 5-8, 5-9). He argued that instead, NEPOOL used a higher forecast, based on the assumption that the boom years of the 1980's would return to New England in the 1990's and cause the peak load to increase sharply (id. at 16-18, citing, Exh. HO-72 at 5-7 to 5-9). The Attorney General further argued that NEPOOL's adjustments conflict with the current state of the economy in that the recent recession was the worst in 20 years and the recovery is modest compared to previous recoveries (id. at 18, citing, Exhs. AG-JH-2; AG-204, at 22-30).[308] With respect to the second component of high side uncertainty, the assignment of probability to the high-load forecast, the Attorney General argued that NEPOOL derived a probability distribution based on a judgmental process without explanation (id. at 18-19).

In addition, the Attorney General argued that the Company compounded NEPOOL errors underlying its probabilistic analysis by utilizing the 1993-1997 expected value forecast to develop a base-case forecast for the years 1992 though 2007 (id. at 21-23). In support, the Attorney General argued that a base-case forecast should be (1) identified through a credible forecasting methodology and set of inputs, and (2) subjected to various sensitivities in order to produce a bandwidth around the forecast and that, therefore, the expected value forecast -- itself derived from bandwidths -- is not statistically suited to serve as a base case

308 The Attorney General argued that NEPOOL's rejection of independent data would subject the high-load forecast to the Company's criticism of the short-term forecast -- that ad hoc adjustments to data developed independently would bring into question the forecast's overall objectivity and reliability (Attorney General Brief at 17-18).

forecast (id. at 21).[309] The Attorney General questioned the use of a linear regression of forecast values for 1993 through 1997 to extend the NEPOOL forecast through 2007 (id. at 22-23).[310] The Attorney General argued that it was inappropriate to extend the forecast beyond 1997 inasmuch as NEPOOL itself suggested that uncertainty surrounding future load levels and resource availability makes it difficult to perform a meaningful probabilistic analysis over the long term (id. at 22-23, citing, Exhs. AG-204, at 21-22; HO-71, at 17).

Finally, the Attorney General asserted that the confidence level reflected in the expected value forecast -- 57 percent to 62 percent -- exceeds consistent Siting Board precedent in planning to a 50 percent confidence level (id. at 15, citing, Exh. SB-JH-RR-8).[311] He argued that the Company did not provide sufficient justification for the Siting Board to depart from such precedent (id.).[312]

With respect to the GDP forecast, the Attorney General argued that it should not serve as a basis for determining need in that it is: (1) theoretically unsound; (2) not statistically

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309 The Attorney General argued that accepting the expected value forecast as a base forecast suggests that a bandwidth should be drawn around the forecast which would be even wider than the expected value forecast (Attorney General Brief at 21-22).

310 Dr. Shakow stated that a "regression analysis properly involves the construction of a fit to actual data" (Exh. AG-204, at 21). He stated that the expected value forecast does not constitute data and that the R-squared values associated with the regression do not demonstrate that the Company has produced a good forecast (id. at 22).

311 The Attorney General stated that the Company's suggestion that need be determined based on a confidence level greater than 50 percent would not achieve such a confidence level but, instead, would lead to a later "honing down" of projects through the IRM process (Attorney General Brief at 10-11). Thus, the Attorney General argued that such a review standard would inappropriately defer siting decisions to IRM (id. at 11).

312 In addition, the Attorney General argued that the expected value forecast, driven by a high load forecast resulting from the rejection of a rigorous objective forecast and judgmental probability assignment, fails to meet the Siting Board requirement that demand forecasts should be fully described and explicitly and completely documented to allow the Siting Board to "fully understand the forecast from the information presented" (Attorney General Brief at 20, citing, 980 C.M.R. 7.03(5)).

validated for the short-term; and (3) based on an arbitrary and unsupported forecast of a single independent variable (Attorney General Brief at 33-36). In support, the Attorney General stated that even though GDP is one determinant of electricity demand, the GDP forecast is theoretically unsound in that it omits primary factors that influence the demand for electricity in New England including personal income, disposable income, real price of electricity, commercial output, and saturation and growth in end-uses (Attorney General Brief at 33-34, citing, Exh. AG-204, at 20; Tr. JH4, at 130). The Attorney General further argued that the GDP forecast was statistically validated in terms of its ability to forecast cumulative change over a 17-year historical period, rather than its ability to forecast year-to-year change (Attorney General Brief at 34-35, citing, Exh. HO-RN-29, att.; Tr. JH4, at 121). Therefore, he argued that the forecast should not be used to predict peak load in 1997, which is only four years away (Attorney General Brief at 34-35).[313] Finally, the Attorney General argued that the GDP forecast incorporates an inflated forecast of GDP to predict New England peak load (id. at 36).[314]

NO-COAL argued that NEPOOL demand forecasts are biased upward in favor of increased electricity consumption and should be replaced with independent forecasts of demand (NO-COAL Brief at III-1). NO-COAL indicated that two specific areas of bias are (1) the forecast of new residential heat customers, and (2) the energy services method of determining cost (id. at III-2). NO-COAL also argued that, instead of speculative forecasts, the Siting Board should consider that the Company has sold only 83 MW of power (id.). Finally, NO-COAL argued that regulatory emphasis should be placed on reducing

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313 The Attorney General argued that the Company underforecast growth in GDP in 1992 but that the GDP forecast still overpredicted load for 1992 (Attorney General Brief at 35).

314 Dr. Shakow testified that the Company's GDP forecast conforms to the "policy forecast" presented in the 1992 Economic Report of the President and that the policy forecast assumed adoption of federal pro-growth policies which were intended to stimulate growth (Tr. 29, at 17-18). He further testified that such federal pro-growth policies were not adopted, and, as such, the lower "business as usual" GDP forecast would have been more appropriate (id., at 18-20).

consumption rather than increasing capacity and that there is no factual evidence to support a need for an additional 300 MW of power in 1997 (id. at III-5).

The Company responded that the Siting Board should not reverse its previous finding of regional need for the proposed facility based on the reference forecast (EEC Reply Brief at 42-44). The Company argued that the reference forecast is biased in a downward direction, especially in the short-run, and should not be considered the primary forecast of regional need (id., at 19, 43-44). The Company noted that the problems in the short-run forecast influence the rate of growth in the period that is of the most relevance (Tr. 27, at 64-66). In addition, Mr. La Capra noted that the electric vehicle forecast does not impact the long-term forecast until the year 2002 (id. at 68). He stated that it was reasonable for NEPOOL to include the electric vehicle forecast in the long-term forecast as it reflects future potential (id.).[315]

In response to criticism of the expected value forecast, the Company stated that the Siting Board has not definitively established that supply planning should reflect the 50 percent confidence level, but that, instead, the Siting Board has given applicants the opportunity to justify a higher level of planning confidence and has found that planning to a 50 percent confidence level may not satisfy reliability concerns (EEC Reply Brief at 15, citing, EEC Decision, 22 DOMSC at 238-240; Boston Edison, Phase I, 24 DOMSC at 282-286).

Regarding the Attorney General's argument that NEPOOL has judgmentally selected a high-side demand case which results in an upward bias to the entire expected value forecast, EEC responded that judgmental development of a forecast does not render it invalid (id., at 16).[316] EEC further argued that the high-side demand forecast is not unreasonably high such that it would bias the entire forecast, but instead is a reasonable high-case scenario

315 The Siting Board notes that NEPOOL calculated that electric vehicles and miscellaneous other factors contribute to a 0.1 percent higher growth rate for 1991 to 2006 (Exh. HO-72, at 1-7).

316 EEC stated that the development of any load forecast is inherently judgmental (Tr. JH4, at 56-57, 82).

because (1) it is based on actual New England economic data, and (2) the most recent economic data has exceeded NEPOOL expectations (id. at 17).[317]

(B) DSM

The Attorney General argued that the Company understated future DSM levels by (1) discounting NEPOOL projected DSM increases over 1991 levels by 25 percent in the base case, and (2) failing to consider potential DSM savings beyond those contained in the reference forecast (Attorney General Brief at 38-43, 111-126). The Attorney General's witness, Mr. Horowitz, provided testimony indicating that the amount of DSM savings included in the reference forecast does not reflect a maximum potential for utility-sponsored DSM (Exh. AG-200).

The Attorney General argued that the Company's concerns about NEPOOL DSM projections -- NEPOOL's historical track record in projecting savings from DSM programs, the DSM uncertainty reflected in the 1992 resource assessment, and the differences between anticipated and measured savings for particular DSM techniques -- provides insufficient justification for discounting NEPOOL DSM projections (id.). The Attorney General stated that although EEC calculated NEPOOL's average forecast error for 1988 through 1991 to be 18 percent, the inclusion of forecast error for 1989 data, which is significantly higher than the forecast error for other years, skewed the results (id. at 39). Mr. Horowitz explained that the high forecast error in 1989 was a one-time event caused by initial implementation of region-wide demand side programs in that year, and, therefore, it was not appropriate to include 1989 data in the analysis of forecast error (id., at 12). He stated that without 1989 data, average forecast error would be reduced to approximately seven percent (id.).[318]

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317 The Company asserted that the low-case forecast is not a reasonable scenario largely based on unreasonably high electricity price increases and, therefore, it creates a downward bias to the expected value forecast (EEC Reply Brief at 17-18).

318 In addition, Mr. Horowitz indicated that the Company's analysis does not account for an overall decrease in NEPOOL DSM forecast errors due to the utilities' increasing understanding of the amount of DSM that can be delivered due to increasing field experience and evaluation (Tr. JH1, at 180-183).

The Attorney General asserted that the expected value DSM forecast, although lower than the reference case DSM forecast, would support an adjustment one-third as large as the Company's 25 percent adjustment (Attorney General Brief at 40-41, citing, Exh. HO-RN-26, att. 2).[319] With respect to the Company's comparison of engineering estimates to actual savings, Mr. Horowitz asserted that the Company's methodology was flawed (Exh. AG-200, at 13-16). Specifically, he stated that utility submissions of projected DSM savings reflect planning estimates rather than the field engineering estimates assumed by the Company (Exh. AG-200 at 14).[320] He also stated that the measured savings of individual DSM programs within the array of a utility's program mix can be higher or lower than estimated savings and, as such, the relationship between the measured savings and estimated savings in one program would not provide a clear representation of the overall utility's performance (id. at 15). Mr. Horowitz maintained that, based on studies of programs of the larger New England utilities, measured savings are in the general range of the planning estimates of DSM savings (id.).[321]

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319 In addition, the Attorney General stated that the Company's DSM projections fail to account for the DSM resources that NEPOOL considers to be available, with short lead times, and implementable during the 1993-1997 time period (Attorney General Brief at 41-42). The Attorney General noted that the Resource Assessment considers potential DSM contingency programs that would be implementable within the 1993 to 1997 time period and would bring DSM impacts above the level evaluated in the Company's high DSM case (id., at 42). In addition, he stated that the Company failed to account for potential interdependency of load growth and DSM (id.).

320 Mr. Horowitz stated that planning estimates are developed before programs are implemented and reflect the utility's estimate of customer participation, measures installed, savings per measure, program costs, hours of use, etc. (Exh. AG-200, at 13). He stated that field engineering estimates are estimates of savings based on program delivery (id. at 14).

321 The Attorney General stated that Mr. La Capra presented a comparison of engineering estimates to measured savings for DSM programs of only three utilities (Attorney General Brief at 43, citing, Exh. HO-RN-23, att. RLC(3)). He stated that, even if Mr. La Capra is correct in assuming that field engineering estimates are the basis of utility submissions to NEPOOL, a discount rate for New England should not be based on such limited data (id.).

In addition to disputing the Company's claim that NEPOOL overforecasts DSM, the Attorney General argued that the utilities in the region could deliver twice the amount of additional cost-effective DSM currently assumed by NEPOOL for each of the next 15 years, and thus, any need for additional resources could be met by additional DSM (id., at 2-3; Tr. JH1, at 23-24, 26, 34-35).[322] In support, Mr. Horowitz stated that utility submissions to NEPOOL do not represent the maximum levels of DSM savings that utilities currently could achieve and that the reference forecast does not reflect the maximum levels of cost-effective DSM that will be available over the forecast period (Exh. AG-200, at 3-11, 16-19). Mr. Horowitz stated that his assessment of increased DSM potential considers rate impacts, technological feasibility and management issues, cost-effectiveness of programs and effects of the current economic downturn (Tr. JH1, at 156-160).

Mr. Horowitz identified a number of specific factors indicating that higher DSM could be achieved including: (1) a regulatory shift away from requiring aggressive conservation efforts and toward a balancing of DSM with associated rate impacts; (2) a lack of utility commitment in acquiring maximum DSM resources; and (3) recent program oversubscription resulting from demand by customers for a greater level of DSM services than provided (Exh. AG-200, at 3-8; Tr. JH1, at 168-169). Mr. Horowitz also cited program operating experience which suggests that delivery of DSM programs could be increased, and identified expected technological improvements which could increase energy efficiency and provide significant savings during the forecast period but are not reflected in utility DSM forecasts (Exh. AG-200, at 9-10, 16-19; Tr. JH1, at 169).[323]

EEC responded that the Siting Board should reject the Attorney General's argument that the NEPOOL DSM projections could be doubled because the Attorney General failed to

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[322] The Attorney General noted that one utility, Western Massachusetts Electric Company ("WMECo"), has in the last year filed with the Department a proposal for a set of programs that would double its DSM savings reflected in the 1992 CELT report (Attorney General Brief at 114, citing, Tr. JH1, at 24-25).

[323] Mr. Horowitz indicated that such technologies include high efficiency office equipment and refrigerators and microwave clothes dryers (Exh. AG-200, at 17).

consider issues that affect implementation of DSM programs including cost effectiveness and regulatory approval (EEC Reply Brief at 44-48). EEC further responded that the Company's base DSM case is the best estimate for determining the contribution of DSM toward providing a necessary energy supply for the Commonwealth (id.).[324]

iii. Analysis

As noted above, the Company developed demand forecasts based on three different forecast methodologies -- the reference forecast, the expected value forecast and the GDP forecast. With respect to the reference forecast, the Siting Board notes that the Siting Council 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 non-utility generator ("NUG") facilities. See Enron Decision, 23 DOMSC at 42; EEC Decision, 22 DOMSC 234-236; MASSPOWER Decision , 20 DOMSC at 321; Altresco Decision, 17 DOMSC at 364; NEA Decision, 16 DOMSC at 354. However, in previous reviews, the Siting Council also stated its concerns with the 1991 CELT forecast that compromised the validity of the forecast, and therefore found that the need cases developed from the 1991 CELT forecast should not be used for the purposes of evaluating regional need. See Enron Decision, 23 DOMSC at 42-43; EEC Decision, at 22 DOMSC at 235-236.

Here, both the Company and the Attorney General expressed concerns with the reference forecast. As noted above, EEC characterized the reference forecast as overly pessimistic, particularly in the near term, while the Attorney General characterized the reference forecast as likely to overstate demand. With respect to the Company's criticisms of the CELT forecast -- overly pessimistic economic trends and high fuel price projections -- the Siting Board notes that such criticisms relate primarily to the short-term forecast.

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324 With regard to the Attorney General's argument regarding a filing by WMECo with the Department that would double DSM savings, the Company asserted that there is no evidence in the record that WMECo has made such a filing, and that utilities in the region are not planning such that DSM savings would be doubled in each year of the planning horizon (EEC Reply Brief at 47-48).

Although the Company claims that dampening of demand in the short term may impact the forecast beyond the 1994 to 1995 transition period, given NEPOOL forecast methodology, it is unclear that any such dampening would significantly impact the forecast in the long term. To develop the reference forecast, NEPOOL produced two separate forecasts -- a short-term forecast, based on an econometric model for the years 1992 and 1993, and a long-term forecast based on an end-use model for the years 1996 and beyond -- and then merged the two forecasts to produce projections for the years 1994 and 1995. Thus, the Siting Board agrees with the Attorney General that even if demand were biased downward for the 1992 to 1993 time frame of the short-term forecast, any downward bias would not have a significant influence on the long-term forecast for the years 1996 and beyond, the critical time frame of need for the proposed facility. In addition, the Company acknowledged that the reference forecast was a reasonable long-term forecast.

The Attorney General, on the other hand, characterized the reference forecast as likely to overstate demand, due, primarily, to the electricity price forecast methodology, the regional economic activity forecast and the electric vehicle forecast, all part of the long-term forecast. The Siting Board notes that, even if the electric vehicle forecast is inappropriate, the electric vehicle forecast is negligible through the year 2000 and has a minimal impact on the forecast overall. In addition, the Siting Board notes that the record does not support a conclusion that the methodological changes within the electricity price forecast or assumptions regarding regional economic activity were unreasonable or that forecast methodology or assumptions produced unreasonably low electricity prices or augmented growth rates to significantly bias the forecast upward.

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

With respect to the expected value forecast, the Company considers the expected value forecast to be a base-case forecast while the Attorney General expressed methodological concerns with the forecast. The Siting Board notes that this is the first time that a facility proponent has provided an expected value forecast to establish regional need and agrees with the Company that a probabilistic approach has potential benefit in assessing the significant uncertainties which impact the timing and magnitude of the need for new resources. The Siting Board further notes that the expected value forecast methodology is somewhat akin to a forecasting method based on a confidence level greater than 50 percent, an approach the Siting Council previously reviewed. BECo Decision (Phase I), 24 DOMSC at 279-286.[325] In that review, the Siting Council found that planning to a confidence level greater than 50 percent may be appropriate for reliability purposes, but indicated that, in order to approve such planning a proponent would be required to provide a cost/benefit analysis to support planning to a higher reliability level. Id. In addition, the Siting Council noted that a proponent should consider the likelihood that all utilities within NEPOOL would agree to acquire resources based on a confidence level greater than 50 percent. Id., 24 DOMSC at n.148. Here, the Company has not addressed either issue in proposing the expected value forecast as a base case forecast. In order to accept the expected value forecast as a base case forecast, further support would be required including a cost/benefit analysis.

Finally, with respect to the Attorney General's arguments concerning inappropriate extrapolation and underlying judgmental biases, the Siting Board notes that extrapolation of the expected value forecast raises accuracy concerns, particularly if viewed as a base forecast, but the record does not establish the extent or direction of any actual inaccuracy. While the Attorney General's arguments have possible merit, if the forecast is viewed simply as a possible or high case forecast, the Attorney General's claimed flaws do not warrant rejection of the forecast.

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[325] The Siting Board notes that both methodologies are based on the NEPOOL Resource Assessment and that the expected value confidence level is pulled above 50 percent by high-side uncertainty -- the requirements underlying the high confidence forecasts in the Resource Assessment.

Thus, the Siting Board finds 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.

With respect to the GDP forecast, the Company characterized the forecast as a moderate-to-high demand forecast while the Attorney General argued that the forecast was based on an inflated forecast of the GDP and was methodologically unsound. In previous reviews of proposed NUG facilities, the Siting Council accepted forecasts based on the historical relationship of the related economic indicator, GNP, and peak load as alternative forecasts in evaluations of regional need, but recognized that such forecasts were based on methodology that was less sophisticated than other forecasts such as the CELT forecast. See Enron Decision, 23 DOMSC at 44, EEC Decision, 22 DOMSC at 236-237. Although the Company did not explain why a GDP-based forecast would predict moderate-to high peak demand, the Siting Board notes two possible explanations: (1) that the forecast of GDP itself is high, as the Attorney General claims, and (2) that the Company's estimate of the historical relationship between GDP and peak load results in an upward bias. With regard to the Company's forecast of GDP, we recognize that such forecasts are by their nature relatively uncertain and open to subjectivity. However, based on the record, the possibility that over-optimistic economic assumptions underlie the GDP forecast is not compellingly greater than the possibility that overly pessimistic economic assumptions underlie the CELT forecast, as claimed by EEC.

With respect to the historical relationship between the GDP and peak load, the Siting Board notes that the GDP forecast has no means to capture possible shifts in such relationship between GDP and peak load that would stem from changes in the rate of DSM implementation. In addition, the Company's analysis showed differences in the historical relationship between the GDP and peak load for different periods.[326] Nevertheless, the

[326] The Siting Board notes that the GDP forecast incorporates an exponential coefficient of 1.1, based on the 1974 to 1991 period. However, the Company defends the GDP forecast based on a 1:1 relationship, (coefficient of 1.0). The recalculation of the historical relationship between growth in GDP and growth in peak load for the 1974 to 1985 period actually shows a coefficient of 1.0. See n.293, above.

Siting Board finds 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.

Finally, with respect to DSM, the Company considered a discount of the 1992 CELT DSM by 25 percent of the increment over 1991 levels to be appropriate in the base case while the Attorney General argued that such discounting is excessive and argued, instead, that the forecast should reflect a doubling of the 1992 CELT DSM levels. The Siting Board agrees with the Attorney General that EEC's discounting of DSM is excessive. The average actual DSM underperformance for the years 1988 through 1991 is 18.2 percent, significantly lower than the 25 percent assumed by the Company. Further, the actual DSM underperformance relating to the 1989 forecast was significantly greater than DSM underperformance relating to the 1988, 1990 and 1991 forecasts,[327] and omitting the 1989 forecast from the analysis results in an average underperformance of only 7 percent. As argued by the Attorney General, it is likely that changes in DSM program emphasis contributed to the overforecasting in the 1989 CELT forecast. Thus, in considering the historical basis for any discounting of NEPOOL-projected DSM levels, it would be reasonable to omit DSM underperformance from 1989. By omitting the actual DSM underperformance for 1989 and substituting instead the average DSM underperformance for 1990, the next largest DSM underperformance, the average DSM underperformance is reduced to 8.4 percent.

Accordingly, the Siting Board finds that it is appropriate to adjust the 1992 CELT DSM levels in the base case. The Siting Board further finds 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.

In addition, the Siting Board has concerns with the Company's selection of its low DSM case. Despite the Company's testimony that engineering estimates, the basis of

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327 See n.297, above.

NEPOOL's current DSM projections, generally overpredict actual DSM savings by 30 percent to 50 percent, the Company's discount of DSM growth above 1991 levels by 50 percent appears to be somewhat arbitrary. Further, the Company provided no justification for assuming a lower low DSM case than the 1992 CELT low DSM case. Accordingly, for the purposes of this review, the Siting Board finds that the Company's low DSM forecast should be adjusted to represent the 1992 CELT low DSM case.

The Siting Board also has concerns with the Company's selection of the high DSM case. The Company provided no justification for assuming a lower high DSM case than the 1992 CELT high DSM case. Further, as noted above, the 1992 CELT high DSM case levels represent a relatively small margin above the 1992 CELT reference DSM case levels. Therefore, for the purposes of this review, the Siting Board finds that the Company's high DSM forecast should be adjusted to represent the 1992 CELT high DSM case.

Finally, while we agree with the Attorney General that increased DSM implementation potentially could occur over the forecast period as a result of policy shifts by utilities and regulators, the Siting Board does not agree that a doubling of the 1992 CELT reference DSM levels should be reflected in the Company's forecast. The Attorney General did not adequately support the assumption that DSM levels could or would be doubled. Given the significant policy changes that would be required for such an increase in DSM implementation, the Siting Board notes that a scenario which assumes the doubling of 1992 DSM levels would be more appropriately considered as a possible contingency rather than as a base or even a high DSM case.

c. Supply

i. Description

(A) Capacity Assumptions

The Company presented three supply forecasts based on the 1992 CELT report -- a base supply case, high supply case and low supply case (Exh. HO-RN-25). The Company asserted that the base supply case represents the most likely forecast of energy resources available to meet the needs of the region over the forecast period (EEC Brief at 52). In addition, the Company asserted that the high and low supply cases would represent a reasonable range of supplies likely to be available over the forecast period and address the most likely uncertainties in potential supply resources (id.).

In support, EEC stated that the base supply case reflects the resources included in the 1992 CELT report, updated to account for recent supply additions and retirements (Exh. HO-RN-25).[328] The Company stated that the high supply case assumes that the base supply case is increased by (1) the continuation of the Hydro-Quebec Phase II contract beyond its scheduled expiration of July 1, 2001, and (2) 50 percent of the proposed, but not yet committed, utility generation project capacity (id.).[329] The Company stated that the low supply case assumes that the base supply case is decreased by 800 MW over the forecast period -- an annual amount of capacity equal to the average of the capacity sizes of the eight remaining New England nuclear units (id.).[330]

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[328] The resources included in the 1992 CELT Report include: (1) existing utility generation; (2) cumulative retirements; (3) committed non-utility generation; (4) net of planned, purchased and sales; (5) other committed capacity additions; and (6) net reratings, and deactivations (Exh. HO-RN-25). Included in committed non-utility generation are all operating units and committed non-utility generators under NEPOOL category "UC," defined as "under construction and/or fully licensed" (id.; Exh. HO-70, at 55). This category includes 181 MW for the AES Thames facility in Connecticut and 222.69 MW for the MASSPOWER facility in Massachusetts (Exh. HO-70 at 69). The Company indicated that the MASSPOWER facility has approximately 3 MW for sale and the AES Thames facility, which has been completed has approximately 20 MW of uncommitted capacity (Exh. HO-MN-52). However, information in the record indicates that the AES Thames facility is a 180 MW facility and that 180 MW is committed (Exhs. HO-B-12; HO-70 at 61).

[329] The Company indicated that the principal projects in this category include (1) the Taunton Energy Center, a proposed 150 MW facility, and (2) Edgar Energy Park, a proposed 306 MW facility (Exhs. HO-RN-25, HO-70, at 31).

[330] EEC indicated that the low supply case is representative of possible contingencies such as: (1) the long-term unavailability or retirement of any one of the existing nuclear units; (2) the long-term unavailability of the Seabrook Nuclear Power Plant ("Seabrook") during the summer peak period due to coastal evacuation concerns; and (3) the general increased lack of reliability experienced across the nuclear industry (Exh. HO-RN-25).

In addition, the Company provided eleven additional supply scenarios as contingency adjustments to its base, high and low supply cases (Exhs. HO-RN-26, HO-RN-28). EEC indicated that contingency adjustments that would increase supply include: (1) the addition of 58 percent of planned but uncommitted NUG projects;[331] (2) the addition of 80 percent of planned but uncommitted NUG projects; (3) the addition of 40 percent of planned but uncommitted NUG projects;[332] (4) the life extension of 25 percent of the capacity of units currently scheduled for retirement; and (5) a decrease in NEPOOL's reserve margin of two percentage points (id.). EEC indicated that contingency adjustments that would decrease supply include: (1) an increase in NEPOOL's reserve margin of two percentage points; (2) the retirement of 25 percent of the capacity of existing units currently operating beyond limits defined by NEPOOL guidelines; (3) adjustment for the expected value for the attrition of existing utility units; (4) adjustment for the expected value for the attrition of existing NUG units; (5) the retirement of fossil plants caused by a change in environmental

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331 Even though the Company indicated that this contingency category includes planned but "uncommitted" NUG projects, this contingency category includes NUG projects under NEPOOL category "C," defined by NEPOOL as "signed power contract with utility, financing not obtained. Not under construction." (Exhs. HO-RN-26; HO-70, at 55). Therefore, NEPOOL category "C" includes only the committed capacity of planned NUG projects. The Siting Board notes that this category includes 83 MW for the committed capacity of the Enron facility (Exh. HO-70, at 73). During the course of the hearings, the Company indicated that the Enron facility, which has an uncommitted capacity of approximately 60 MW, may now be under construction (Exh. HO-MN-52). In updating information relative to the supply for the Massachusetts need analysis, EEC added 58 MW for Enron committed capacity to the base case for the prorated share to Massachusetts and removed a similar capacity from this contingency category and also decreased Massachusetts purchases from the Power Authority of the State of New York ("PASNY") based on updated data which indicated original estimates were too high (Exh. SB-JH-RR-11). The Company did not apply either of these adjustments to the regional supply forecast.

332 EEC indicated that it considers the base NUG success rate to be 58 percent, and the high and low NUG success rates to be 80 percent and 40 percent, respectively (Exh. HO-RN-28). EEC further indicated that the addition of the high and low NUG success rate cases corresponds to a Siting Council request in the EEC Decision to vary the assumed NUG success rate by approximately 20 percent (id.).

regulations;[333] and (6) adjustment for the expected value for the capacity of the Hydro-Quebec Phase II project ("Hydro-Quebec") (Exh. HO-RN-26).[334]

(B) Reserve Margin

EEC indicated that it assumed a reserve margin of 22.5 percent of peak demand, consistent with the analysis previously provided in the EEC Decision, and that the 22.5 percent reserve margin reflects the impacts of particularly large generating units on the overall loss of load probability faced by NEPOOL (Exhs. HO-RN-24, HO-1A at 52-53, HO-RN-8).[335] However, the Company also indicated that it would be reasonable to decrease the reserve margin slightly if Seabrook reaches a mature level of operation (EEC Reply Brief at 23). The Company stated that, while there is no guarantee that a large nuclear unit such as Seabrook would ever reach the improved availability associated with mature operation, it is a possibility that should be considered in the analysis (id., citing, Exh. SB-JH-RR-11). In response to a request of the Siting Board Staff, the Company also prepared an analysis reflecting a lower reserve margin resulting from an assumed Seabrook maturity (SB-JH-RR-11).

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333 EEC indicated that the federal Clean Air Act, Massachusetts acid rain legislation and other potential new legislation will lead to the retirement of certain older fossil fuel-fired units (Exh. AG-RE-77).

334 The Company stated that the contingency that reflects the retirement of fossil plants caused by a change in environmental regulations was not included in the contingency that reflects the attrition of existing utility units (Tr. 28 at 5-7). Mr. La Capra explained that the conditions that would cause the attrition of existing utility units, such as the likelihood of it being more costly to maintain a unit on-line than shut it down, would exist absent a specific policy to shut units down for environmental reasons (id.). However, EEC added that one 115 MW unit would be included in both categories (id. at 7).

335 In the EEC Decision, the Company applied a 20 percent reserve margin to demand forecasts which did not include the capacity of Seabrook, and a 22.5 percent reserve margin where the capacity of Seabrook was included (22 DOMSC at 218).

ii. Positions of the Intervenors and Company Response

(A) Capacity Assumptions

The Attorney General argued that the Company's supply forecast is understated due to the omission of certain supply options from the base supply case (Attorney General Brief at 43-44). First, the Attorney General stated that the Company's base supply case includes only the committed portion of NUG units that are existing or under construction, but instead, should include the entire capacity of these units (id.).[336] Next, the Attorney General stated that the extension of the Hydro-Quebec contract beyond the year 2000 also is omitted from the base case even though the Company did not evaluate the availability of the Hydro-Quebec resource beyond the year 2001 (id. at 44-45). He stated that the capacity position of the region would significantly improve if the Hydro-Quebec contract were extended beyond the year 2000 and that it would, therefore, be irresponsible to plan new power plants based on the assumption that Hydro-Quebec would cease supplying power as of 2001 (id. at 44-45, citing, Tr. JH8, at 8).

The Attorney General further argued that the Company's low and high supply cases also understate supply (id. at 51-63). He maintained that EEC provided no justification for assuming the retirement of one entire nuclear unit as part of the low supply case (id. at 52).[337] In addition, he maintained that the low supply case overlaps with the contingency that reflects the expected value for the attrition of utility units, thus, double-counting capacity subtractions (id. at 50, 52). Therefore, the Attorney General argued that the low supply case should be disregarded (id. at 52).

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336 The Attorney General argued that the entire capacity of the Enron facility, 146 MW, should be included in the Company's base supply case and that the uncommitted capacity of the MASSPOWER and AES Thames facilities totalling 23 MW should be included as well (Attorney General Brief at 43-44, n.9). See Section II.C.3.c.ii., below.

337 The Attorney General asserted that the Company provided no basis for the assumptions that a nuclear facility is about to be shut down, Seabrook would not operate during summer months, or there would be a series of nuclear facility outages (Attorney General Brief at 52).

The Attorney General asserted that the high supply case assumes (1) a Hydro-Quebec contract extension which would not affect supply until the year 2001, and (2) a pessimistic 50 percent success rate for planned utility additions and therefore is too low (id. at 52-53, citing, Exh. HO-RN-25).[338]

In addition, the Attorney General argued that the Company's supply scenarios underestimate likely future supply (id. at 47-63). First, he argued that EEC's supply scenario analysis was not an objective assessment because: (1) the analysis does not reflect a neutral criterion for selecting scenarios;[339] (2) scenarios are not weighted according to their relative probabilities of occurrence; and (3) scenarios overlap and therefore double-count certain capacity subtractions (id. at 47-51).[340]

The Attorney General further argued that, in general, the supply scenarios were based on unsupported assumptions, and were flawed and understate supply (id. at 54-63).[341] For

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338 The Attorney General disagreed with the Company's characterization of the high supply case as overly optimistic in that this category includes Boston Edison Company's Edgar project (Attorney General Brief at 53-54). The Attorney General noted that if the Siting Board adopts the Tentative Decision on site-banking, the Edgar project could be available to meet a near term need (id. at 54). The Siting Board adopted the Tentative Decision as amended on August 5 1992.

339 The Attorney General argued that, although EEC indicated that supply scenarios were generally selected for consistency with the Resource Assessment, four of the nine Company scenarios are not included in the resource assessment and four of the nine uncertainties analyzed in the resource assessment are not incorporated in the same form in the Company's analysis (Attorney General Brief at 48, citing, Exh. HO-71, at 6-7; Tr. JH5, at 24).

340 For instance, the Attorney General maintained that the low supply case and three supply scenarios involve the unplanned retirements of utility units and thus overlap (Attorney General Brief at 49-50). He asserted that the supply scenario that reflects the attrition of existing utility units incorporates the low supply case as well as the supply contingencies that reflect both the 25 percent failed life extension projects and fossil plant retirements due to environmental issues (Attorney General Brief at 49-50).

341 The Attorney General also argued that supply scenarios derived from the resource assessment are unreviewable in that the basis for probability distribution functions is (continued...)

instance, he asserted that (1) supply scenarios that consider life extensions and retirements apply only to partial units; (2) the supply scenario which assumes a NUG success rate of 58 percent was understated because the assumed success rate is too low and proposed projects were incorrectly excluded from consideration; and (3) the contingencies relative to the expected value of existing utility and NUG attrition were based on incorrect data (Attorney General Brief at 54-62).[342]

NO-COAL argued that EEC's supply scenarios are biased and include unreasonable assumptions such as the shut down of the Pilgrim facility in 1993 and the curtailing of Hydro-Quebec purchases in 2001 (NO-COAL Reply Brief at II-1). NO-COAL suggested that scenarios that increase supply should be included and that the Siting Board should compare EEC's supply forecasts to recent forecasts of investor-owned utilities (id.).

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[341](...continued)
not documented and the full probability density distribution is not provided (Attorney General Brief at 58). He further argued that contingencies relative to the expected value of existing utility and NUG attrition and Hydro-Quebec capacity represent a confidence level higher than 50 percent (id. at 62-63).

[342] The Attorney General argued that the expected value for future NUG resources reflected in the resource assessment is higher than the Company's assumed success rate of 58 percent (Attorney General Brief at 55, citing, Exh. HO-RN-26, att. 2 at 40). In addition, the Attorney General argued that the Company incorrectly excludes those planned NUG units classified by NEPOOL as category "I," "Intent to purchase from non-utility generator, no signed power contract. Not under construction." (Attorney General Brief at 55-56, citing, Exh. HO-70, at 55). The Attorney General argued that in excluding category "I," the Company suggests that competing NUG projects should be ignored in the Siting Board determination of need (Attorney General Brief at 56). The Attorney General argued that, instead, the Siting Board should not treat competing NUG projects in isolation from each other (id.).

The Siting Board notes that there are three pending petitions for approval of NUG projects, the proposed Altresco-Lynn facility, 170 MW, the proposed Island End Cogeneration Project, 235 MW, and the proposed Taunton Energy Center project, 150 MW. The Siting Council further notes that category "I" includes 25 MW (claimed summer capacity) for the proposed Altresco-Lynn facility and does not include the proposed Cabot facility (Exh. HO-70, at 76). As noted above, 50 percent of the proposed Silver City project is included in the high case as proposed utility generation.

With respect to the base supply forecast, EEC responded that Hydro-Quebec was excluded from the base-supply case after the year 2000 consistent with NEPOOL exclusion of Hydro-Quebec as a committed supply after that year (EEC Reply Brief at 26-27, citing, Exh. HO-71).

With respect to the Attorney General's argument that the Company's supply scenario analysis does not reflect a neutral criterion for selecting scenarios and are biased toward supply contractions, the Company responded that its supply scenarios were consistent with those considered by NEPOOL in its Resource Assessment and the Siting Council previously noted that there simply are not as many events which can increase available resources as there are possible events to reduce resources (EEC Reply Brief at 28-31, 34, citing, EEC Decision, 22 DOMSC at 239). Further, with respect to the Attorney General's argument that the scenarios overlap and thus double-count the capacity subtractions associated with particular uncertainties, the Company responded that the scenarios presented provide reasonable alternative views of the future based on combinations of factors that affect supply (id. at 31-34). EEC asserted that it is reasonable and appropriate to offer different sensitivity cases which vary the level of impact on a variable such as the future availability of existing utility resources (id. at 32-33). Finally, with respect to the Attorney General's arguments regarding the inclusion of computing NUG projects in the contingency analysis, the Company responded that the projects included in NEPOOL category "C" are appropriate to consider given that they are in the development process and could be potential resource options while those projects included NEPOOL category "I" are not appropriate to consider given they are so speculative (id. at 38).

(B) Reserve Margin

The Attorney General argued that the Company's assumed reserve margin of 22.5 percent is unreasonably high (Attorney General Brief at 45). The Attorney General argued that, at most, the reserve margin should be 21.7 percent (id. at 46).[343] He also argued that

[343] The Attorney General indicated that EEC based its reserve margin requirement on the "1989 Annual Review of NEPOOL Required Reserves and Objective Capability for (continued...)

reserve margins should even be lower based on the reserve margins set forth in the Resource Assessment (id. at 46). He asserted that, assuming the reference load case and rounding, the Resource Assessment targets reserve requirements of 22 percent in 1998, 21 percent from 1991 through 2001, and 20 percent from 2002 through 2007 (id., citing, Exh. HO-RN-26, att. 2 at 13 and n.1). He added that the Resource Assessment specifies even lower reserve margins when higher loads are assumed (id., citing, HO-RN-26, att. 2 at 13).[344] The Attorney General further argued that, given the Company's position that Seabrook added 2.5 percent to the reserve margin for the region, the reserve margin also should be decreased in the low supply case (id. at 51, n.16).

The Company responded that the reserve margin should be increased rather than decreased under the low supply case (EEC Reply Brief at 35). EEC explained that, because the low supply case assumes that the availability of a relatively larger unit would decline, in order for NEPOOL to maintain its reliability criterion, reserves should be increased to account for this unit (id.). EEC noted that, instead, it assumed a consistent 22.5 percent reserve margin in the base and low supply cases (id.).

(C) Analysis

As noted above, the Company presented a base supply forecast based on the 1992 CELT report, a high supply forecast based on possible implementation of supply options

[343](...continued)

Power Years 1989/90 through 1993/4" (Attorney General Brief at 45, citing, Tr. JH 4, at 149). He maintained that this document indicates that required reserves of 20 percent should be increased by only 1.7 percent when the operation of Seabrook reaches maturity, i.e., Seabrook has been in operation for five years (id., citing, Exh. HO-RN-22; Tr. JH4, at 149). He stated that the lower reserve margins would therefore be appropriate within five years of the June 1990 start date of Seabrook (id., citing, Exh. HO-RN-22; Tr. JH4, at 146).

344 The Siting Board notes that within the Resource Assessment, NEPOOL targeted adjusted required reserve requirements to meet the reliability criterion for the high, reference and low loads ranged from: (1) 21 percent to 22 percent for 1998; (2) 20 percent to 22 percent for 1999; (3) 20 percent to 21 percent for 2000 (Exh. HO-RN-4(a), Table 3). The Siting Board further notes that higher reserve requirements were required for lower loads (id.).

listed in the 1992 CELT report and a low supply forecast, based on possible losses of committed capacity included in the base case. The Company characterized the base supply forecast as the most likely forecast of energy resources available to meet regional need and the high and low supply forecasts as representative of a reasonable range of supplies, given the uncertainties in potential supply resources. The Attorney General, on the other hand, argued that each of the three supply scenarios understate supply.

With respect to the base supply case, the Attorney General raised concerns regarding the exclusion of (1) the extension of the Hydro-Quebec contract, and (2) both the committed and uncommitted capacity of NUG projects that are existing or under construction. The Siting Board notes that the base supply case, which reflects the committed resources included in the 1992 CELT report, updated to account for recent supply additions and retirements, represents the existing energy resources likely to be available to meet the needs of the region over the forecast period. As such, it is reasonable that the base supply case does not assume extension of existing contracts that are due to expire or life extension of existing facilities that are due for retirement during the forecast period. Thus, the exclusion of the extension of the Hydro-Quebec contract from the base supply case is consistent with the resources assumed by NEPOOL over the forecast period, as well as the Company's consideration of various other existing resources that are not planned to continue throughout the forecast period. Therefore, the Siting Board agrees with the Company that the extension of the Hydro-Quebec contract is appropriately included in the high supply case rather than the base supply case.[345]

With respect to NUG projects that are existing or under construction, the Siting Board agrees with the Attorney General that the committed capacity of such NUG projects should

[345] The Siting Board notes that even if the extension of the Hydro-Quebec contract were included in the base supply case, it would only affect supply in the years 2001 and beyond.

be included in the Company's supply cases.[346] However, the Siting Board disagrees with the Attorney General that the uncommitted capacity of such NUG projects also should be included in the base supply case.[347] The consideration of the uncommitted capacity of these NUG projects is akin to the consideration of existing but uncommitted utility-owned capacity, such as the extension of the Hydro-Quebec contract, other contracts due to expire, or life extensions for existing generating units planned for retirement during the forecast period. Although the infrastructure is in place such that the above capacity could be available, the availability of capacity is not certain over the forecast period. Thus, the uncommitted capacity of NUG projects that are existing or under construction would be appropriate for the high supply case rather than the base supply case. Accordingly, the Siting Board finds 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.

The Siting Board also disagrees with the Attorney General that the low supply case should be discarded because it is included in the contingency that reflects attrition of utility units. As discussed below, the contingency analysis serves a different purpose than the high and low supply cases. Even if there is some overlap, it is still appropriate to consider a likely change in supply resources, such as the loss of a nuclear unit, as a low supply case. While the Company might have considered discounting the incremental loss of nuclear capacity to reflect the uncertainty of such loss, use of 100 percent of that capacity is not unreasonable given that there are a number of nuclear units represented. Thus, the low supply case represents a reasonable low range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds that the low supply case, including

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346 As noted above, the Company amended the Massachusetts supply forecast to include the committed capacity of Enron because it was under construction. We have assumed that a comparable correction is reasonable to include in the regional need analysis. See n.351, below.

347 The uncommitted capacity of NUG projects that are existing or under construction includes 3 MW for MASSPOWER and 63 MW for Enron. See n.328, n.331, above.

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.

In addition, the Siting Board disagrees with the Attorney General that the high supply case is pessimistic given that the extension of the Hydro-Quebec contract would not affect supply until the year 2001 and only 50 percent of planned utility additions is included. With regard to the first year of the inclusion of the Hydro-Quebec contract, the Siting Board disagrees with the AG that this results in a pessimistic case as lead time is required for any supply addition. The Siting Board also recognizes that the 1992 CELT report includes planned on-line dates for planned utility additions that clearly are uncertain including (1) January, 1995 for the Taunton Energy Center, and (2) January, 1996 for the Edgar Energy Park. A 50 percent success rate for planned utility additions is reasonable, given the uncertainties as to whether, and of equally critical concern when, such facilities may come on line. However, as noted above, the high supply case should be adjusted by 66 MW to account for the uncommitted capacity of NUG projects that are existing or under construction.[348] Thus, as adjusted, the high supply case represents a reasonable high range of supply likely to be available over the forecast period. Accordingly, the Siting Board finds 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.

With respect to supply contingencies, the Siting Council, in recent reviews of NUG projects, supported applicants' consideration of an increasing extent and variety of forecast scenarios to provide a basis for establishing need. See Enron Decision, 23 DOMSC at 39-40; EEC Decision, 22 DOMSC at 238-239; West Lynn Decision, 20 DOMSC at 32; MASSPOWER Decision, 20 DOMSC at 321-322. Here, in response to the methodological findings in previous reviews, EEC has provided an analysis of eleven supply contingency

[348] See n.347, above.

adjustments to each of its three supply cases and has provided a compilation of the capacity positions for all supply scenarios (see Section II.C.3.d.i., below).

However, the Attorney General correctly argues that the selection of scenarios is sensitive to an applicants' scenario selection process and reflects a degree of subjectivity on the part of the applicant.[349] In addition, the Siting Board agrees with the Attorney General that the Company's compilations of scenarios represents a weight-of-the-scenario approach without any explicit analysis of the relative probabilities of the scenarios.[350]

Given the limitations, a need determination should not be based on the simple counting of a wide range of such scenarios (see Section II.C.3.d.iii., below). At the same time, the Siting Board recognizes the usefulness of a scenario analysis in reflecting a range of potential capacity positions. However, it is not necessary for an applicant to attempt to identify or compile capacity position results for an exhaustive or all-inclusive range of contingency scenarios.

With response to the Attorney General's argument that the Company incorrectly excluded planned uncommitted capacity from NUG projects from its analysis, the Siting Board notes that uncommitted NUG projects have been included in the contingency analyses in previous reviews of proposals to construct NUG projects. See Enron Decision, 23 DOMSC at 32-33. While the likely availability of planned but uncommitted NUG projects could be an appropriate supply contingency, its absence here does not invalidate the Company's analysis. As noted above, a contingency analysis should represent a range of potential regional supply scenarios but an applicant is not required to consider every possible regional supply outcome that could occur over the forecast period.

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349 However, the Siting Board does not agree with the Attorney General that the supply scenarios are biased toward supply contractions. The Siting Council previously recognized that, based on the contexts of supply resource planning decisions that may exist at different times, there are more contingencies that would decrease supply rather than increase supply. EEC Decision, 22 DOMSC at 239.

350 See n.352, below.

Accordingly, for the purposes of this review, the Siting Board finds 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.

Finally, with respect to the reserve margin, the Siting Board agrees with the Attorney General that the reserve margin assumed by the Company, 22.5 percent over the forecast period, is too high, given NEPOOL's expectations concerning long-term reserve margins. We note that the Company also acknowledges that it would be reasonable to decrease the reserve margin slightly below 22.5 percent if Seabrook reaches a mature level of operation.

With respect to NEPOOL expectations, the Resource Assessment projects a downward trend in the reserve margin required to meet its reliability criterion. The midpoint of NEPOOL's target reserve margins to meet its reliability criterion for high, low and reference demand forecasts, after 1997, is: (1) 21.5 percent for 1998; (2) 21 percent for 1999; and (3) 20.5 percent for 2000. The Siting Board also notes that, given the downward trend in NEPOOL-assumed reserve margin requirements, it also would be reasonable to assume a decline from the Company's assumed 22.5 percent reserve margin beginning in 1997. Therefore, based on the foregoing, for the purposes of this review, the Siting Board finds 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.

d. Need Forecasts

i. Description[351]

The Company developed 27 need forecasts based on a comparison of its nine demand forecasts -- the reference, expected value and GDP forecasts each adjusted by base, high and low DSM scenarios and three supply forecasts -- base, high and low (Exh. HO-RR-134). Comparing the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 300 MW of capacity in the early year of proposed project operation is: (1) 15 need forecast scenarios, 55.6 percent, in 1997 (2) 22 need forecast scenarios, 81.5 percent, in 1998; (3) 26 need forecast scenarios, 96.3 percent, in 1999; and (4) 27 need forecast scenarios, 100 percent, in 2000 and beyond (Exh. HO-RR-134). See Table 5. The Company indicated that comparison of the expected value forecast incorporating EEC's base DSM assumptions with the 1992 CELT capacity forecast with updated information ("base need scenario") showed a need for over 300 MW in the early years of the proposed project, specifically: (1) 1,101 MW in 1998; (2) 1,868 MW in 1999; and (3) 2,605 MW in 2000 (Exh. HO-RN-14A). See Table 5.

EEC then subjected each of the 27 need forecasts to eleven contingencies which would increase or decrease supply, generating 297 contingency cases (Exh. HO-RR-134). A summary of the regional need cases indicated that the cumulative number and percentage that demonstrated a need for at least 300 MW was: (1) 177 need cases, 54.6 percent, in 1997; (2) 255 need cases, 78.7 percent, in 1998; (3) 305 need cases, 94.1 percent, in 1999; (4) 319

[351] Given that the Company recalculated the Massachusetts need forecasts to include the committed capacity of the Enron facility, the committed capacity of the Enron facility was included in the regional need forecasts discussed in this section. However, no adjustment was made for purchases from PASNY because there is no indication whether there was a change in overall purchases or in the allocation of purchases to Massachusetts (see n.331, above). Thus, in comparing the need forecast scenarios in this section, the base, high and low supply forecasts were increased by 83 MW -- the committed portion of the Enron facility. In addition, an appropriate amount of capacity was deducted from the three contingencies that increased supply by 80 percent, 58 percent and 40 percent of the planned but uncommitted NUGs.

need cases, 98.5 percent in 2000 and (5) 324 need cases, 100 percent in 2001 (id.).[352] A summary of the 72 common-case need cases, those need cases common to both the regional and Massachusetts need analyses, indicated that the cumulative number and percentage of cases that demonstrated a need for a least 300 MW was: (1) 21 cases, 29.2 percent, in 1997; (2) 48 cases, 66.7 percent in 1998; (3) 68 cases, 94.4 percent, in 1999; and (4) 72 cases, 100 percent, in 2000 (Exh. HO-RR-137).

The Company also presented two additional regional need analyses in response to requests of the Siting Board based on (1) a 21 percent reserve requirement instead of a 22.5 percent reserve requirement in the years 1998, 1999, 2000 and 2001,[353] and (2) the levels of DSM assumed by NEPOOL in its high DSM forecast instead of the levels of DSM assumed by the Company in its high DSM case (Exhs. HO-RR-135, HO-RR-136). EEC stated that neither the change in assumed reserve margin[354] nor the assumed high DSM

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352 The Siting Board notes that the Company did assign relative probability scores to the demand forecasts, DSM forecasts, supply forecasts and supply scenarios (Exh. AG-RE-82, sup.). However, the Company indicated that the relative probability scores of the various cases was of minimal importance given that 99 percent of the cases show a need for at least 300 MW by the year 2000, within four years of the projected in-service date of the proposed facility (id.). Further, the Company did not provide substantive justification for the assigned probabilities.

353 The Company provided recalculations for the 324 need scenarios (Exh. HO-RR-135). For the two contingencies reflecting two percent higher and lower reserve margins, the Company adjusted the reserve requirement by 24.5 percent and 20.5 percent (id.). These adjustments were equal to the adjustment utilized for the need scenarios reflecting a 22.5 percent reserve margin (Exh. HO-RN-13A).

354 With respect to the change in assumed reserve margin, the Company's base need scenario showed a surplus of 300 MW for 1997 and a need for: (1) 759 MW in 1998; (2) 1,517 MW in 1999; and (3) 2,245 MW in 2000 (Exh. HO-RR-135). In addition, the first year of continuous need for 300 MW was delayed by one year in 57 cases, moving from (1) 1998 to 1999 in 27 cases; (2) 1999 to 2000 in 19 cases; and (3) 2000 to 2001 in 11 cases (Exhs. HO-RR-134, HO-RR-135). As such, the cumulative number and percentage of cases that demonstrated a need for at least 300 MW changed to: (1) 228 cases, 70.4 percent, in 1998; (2) 285 cases, 88.0 percent in 1999; (3) 307 (continued...)

levels significantly affected the timing of the first year of continuous need in the regional need analysis (Exh. HO-RR-135).

With regard to an assessment of need based on the NEPOOL high DSM forecast, EEC indicated that, assuming its base supply forecast, the first year of continuous need for at least 300 MW would be 1998 under the expected value forecast, 2000 under the reference forecast, and 1997 under the GDP forecast (Exh. HO-RR-136).[355] Thus, compared to the base supply forecast in conjunction with the EEC high DSM levels, the first year of continuous need would not change under the expected value or GDP forecasts but would be delayed by one year under the reference forecast (id.; Exh. HO-RR-134).[356]

ii. Positions of the Intervenors and the Company's Response

The Attorney General argued that evaluation of the need for a proposed facility by the mere multiplication of need scenarios is meaningless where the supply scenarios do not reflect neutral selection criterion, are not weighted according to their relative probabilities of occurrence, and overlap with each other (see Section II.C.3.c.ii., above) (Attorney General Brief at 47-48).

In addition, the Attorney General argued that the need for the proposed project should not be based on a time frame later than the first year that the proposed project would be on-line (id. at 11-12). The Attorney General stated that the Siting Board has never approved a non-utility power project that is not likely to be needed its first year of operation (Attorney

[354](...continued)
cases, 94.8 percent in 2000 and (4) 324 cases, 100 percent in 2001 (id.).

The Company indicated that all changes in the first year of continuous need for 300 MW occurred under the reference and expected value forecasts (Exh. HO-RR-134, HO-RR-135). As such, all changes occurred within "common case" need scenarios.

[355] The Company's analysis under the NEPOOL high DSM scenario did not include the contingencies of high and low NUG success rate (Exh. HO-RR-136).

[356] The Company's analysis also indicated that under the NEPOOL high DSM scenario, as opposed to EEC's high DSM scenario, the first year of continuous need for 300 MW would be delayed by one year in eleven cases (Exhs. HO-RR-134, HO-RR-136).

General Brief at 11-12). Here, he argued, the Company is suggesting that the Siting Board find need if the project is needed at any time within five years of initial operation (id.).

The Company responded that the Siting Council never determined that it would be inappropriate to consider the need for a proposed facility beyond the first year of operation and that, in fact, the Siting Council, in two previous reviews of NUG projects, considered need in years beyond the first year of proposed facility operation (EEC Reply Brief, n.3, citing, West Lynn Decision, 22 DOMSC at 11-36, Enron Decision, 23 DOMSC at 49). The Company asserted that, given the uncertainties regarding load growth and in-service date of a generating facility, it is appropriate to consider the need for a project beyond the first year of operation (id.).

iii. Analysis

As noted above, the Siting Board agrees with the Attorney General that, given the degree of choice in the Company's identification of supply contingency scenarios and lack of explicit analysis of the relative probabilities of such scenarios, evaluation of need should not be based on a simple counting of the total number of need cases that demonstrate need in a given year. Instead, the Siting Board focuses on the 27 need forecasts that reflect combinations of the Company's three demand forecasts, three DSM forecasts, as adjusted, and three supply forecasts -- base, high and low. As noted above in Section II.C.2.c, the Siting Board considers the Company's remaining contingency cases, which reflect the supply contingencies, to represent an illustration of the potential variability of capacity positions over the forecast period -- rather than a basis for assessing need based on actual compilation of cases.

With regard to the time frame of a need determination, the Siting Board agrees with the Company that it is appropriate to explicitly consider need within a time frame beyond the first year of facility operation. The Siting Council previously considered capacity position beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of two NUG projects. See West Lynn Decision, 22 DOMSC at 14, 33-34, Enron Decision, 23 DOMSC at 49. The longer time frame is potentially useful regardless of whether need has or has not 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.[357] Thus, for the purposes of this review, the Siting Board finds that it is appropriate to explicitly consider need for the proposed facility within the 1997 to 2000 time period.

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels in the base DSM case; (2) the Company's low DSM forecast to represent the NEPOOL low DSM case; (3) the Company's high DSM forecast to represent the NEPOOL high DSM case; (4) the Company's high supply forecast by 66 MW include the uncommitted capacity of NUG projects that are existing or under construction; and (5) the Company's assumed reserve margin of 22.5 percent to reflect lower levels after 1996, specifically 22 percent for 1997, 21.5 percent for 1998, 21 percent for 1999, and 20 percent for 2000.

With respect to the Company's demand forecasts, the Siting Board has found that (1) the reference forecast is an appropriate base case forecast for use in an analysis of regional demand for the years 1996 through 2007; (2) the expected value forecast is an acceptable forecast for use in an analysis of regional demand but should not constitute a base case forecast; and (3) the GDP forecast provides a possible high-case forecast, while recognizing that the forecast methodology is not sophisticated and that possible adjustments may be needed to reflect DSM trends over the forecast period.

While accepting the expected value and GDP forecasts for use in an analysis of regional demand, the Siting Board identified concerns with both approaches. The identified concerns affect the weight the Siting Board places on these forecasts. As a result, for purposes of this review, the Siting Board places more weight on the reference forecast.

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357 As explained above, an analysis of capacity position is not the only basis by which a facility proponent can establish need. Instead, need also can be established by a combination of factors related to the energy supply. See Section II.C.2, above.

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

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 300 MW in each year, from 1997 through 2000, is as follows:

Forecast	1997	1998	1999	2000
Reference forecast (9 cases)	0 (0%)	1 (11%)	4 (44%)	6 (67%)
Expected value/GDP forecasts (18 cases)	13 (72%)	16 (89%)	18 (100%)	18 (100%)
Total (27 cases)	13 (48%)	17 (63%)	22 (81%)	24 (89%)

The capacity positions under the need forecasts, as adjusted, are shown in Table 6. Considered with the base DSM forecast, and the base supply forecast: (1) the reference forecast shows a need for 607 MW in 2000; (2) the expected value forecast shows a need for 596 MW in 1998; and (3) the GDP forecast shows a need for 923 MW in 1997.

In sum, 13 of the Company's 27 need forecasts, including the 18 need forecasts that incorporate the expected value or the GDP forecast, show a need for at least 300 MW in 1997, 16 show a need for at least 300 MW in 1998, 22 show a need or at least 300 MW in 1999 and 24 show a need for 300 MW in 2000. However, none of the nine need forecasts that incorporate the reference forecast show a need for at least 300 MW in 1997, one such forecast shows a need for at least 300 MW in 1998, four such forecasts show a need for at least 300 MW in 1999 and six show a need for at least 300 MW in 2000. Accordingly, based on the foregoing, the Siting Board finds need for 300 MW or more of additional energy resources in New England for reliability purposes beginning in 2000 and beyond.

4. Massachusetts' Need

a. Introduction

EEC asserted that there is a need for new capacity in Massachusetts beginning in 1997 or earlier, and continuing beyond 1997 (EEC Brief at 36). The Company further asserted that the need for new capacity in Massachusetts arises earlier than the need for new capacity in New England as a whole (id. at 36-37). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based in part on 1992 forecast documents and other data published by NEPOOL and, as necessary, prorated to Massachusetts by the Company (Exhs. HO-MN-39; HO-MN-44; HO-MN-47; HO-MN-48; HO-MN-52; HO-MN-53; HO-MN-54; HO-MN-55). The Company combined its demand and supply forecasts to provide a series of Massachusetts need forecasts, and also subjected the need forecasts to a variety of contingency tests to evaluate the sensitivity of the need forecasts to the uncertainty inherent in underlying forecast assumptions (Exhs. HO-MN-39; HO-MN-56; HO-MN-57; HO-MN-58; HO-MN-59).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including the demand forecast methodologies and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including the capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the need forecasts which are based on a comparison of the various demand and supply forecasts.

b. Demand Forecasts

i. Description

The Company presented 11 forecasts of Massachusetts adjusted peak load demand (Exh. HO-MN-39, attached exhibit at 2-4). The Company stated that it based its Massachusetts demand forecasts on five different demand forecast methodologies and three different forecasts of reductions in peak demand resulting from utility-sponsored DSM programs (id. at 2). To derive its 11 demand forecasts, the Company indicated that it adjusted results from three of its forecast methodologies to reflect the three respective DSM forecasts (id.). The Company utilized results from the remaining two forecast methodologies without separate reductions to reflect DSM (id.).

(A) Demand Forecast Methodologies

The five demand forecast methodologies utilized by the Company included: (1) the NEPOOL 1992-2007 energy and peak load forecast for Massachusetts, a companion forecast to the reference forecast incorporated in the Company's regional need analysis ("Massachusetts reference forecast"); (2) a Massachusetts expected value forecast, derived from the NEPOOL 1993-1997 expected value load forecast presented in the 1992 Resource Adequacy Assessment; (3) a variation of the Massachusetts reference forecast, based on a constant annual growth rate ("CAGR") projection between 1992, or first year, peak load and 2007, or end year, peak load as forecasted by NEPOOL in the Massachusetts reference forecast ("Massachusetts end year CAGR forecast"); (4) a historical time series linear regression forecast, based on projection of the 1974-1991 linear regression trend over the 1992-2007 forecast period ("Massachusetts linear regression forecast"); and (5) a historical time series CAGR regression forecast, based on projection of the 1974-1991 CAGR regression trend over the 1992-2007 forecast period ("Massachusetts CAGR regression forecast") (id. at 2-3). The Company stated that its Massachusetts reference forecast was obtained directly from a published NEPOOL source, and the remaining demand forecasts were based on data derived largely from reports published by NEPOOL and its affiliated New England Power Planning Committee ("NEPLAN") (Exhs. HO-MN-39, attached exhibit at 2-3, Attachment 7-1; HO-RN-23; EEC Brief at 17).

The Company stated that two of its Massachusetts demand forecast methodologies -- the Massachusetts reference forecast and the Massachusetts expected value forecast -- correspond to demand forecast methodologies used in the regional need analysis (Exh. HO-RR-137). Repeating arguments from its regional need analysis (see Section II.C.3.b.i, above), the Company characterized the Massachusetts reference forecast as a reasonable long term forecast, but cautioned that the forecast was overly pessimistic in the short term (EEC Brief at 21).[358]

In support of its Massachusetts expected value forecast, the Company again repeated arguments from its regional need analysis, asserting that the NEPOOL expected value forecast (1) is the product of a sophisticated methodology, and (2) incorporates a probabilistic approach which is preferable to a deterministic approach because it is inherently better able to reflect the potential impacts of the significant uncertainties that affect the timing and magnitude of the need for new energy resources (id. at 19).[359] Additionally, the Company asserted that the attributes of NEPOOL's expected value forecast make it an attractive base case demand forecast methodology for Massachusetts, as well as the region as a whole (Exh. HO-MN-43).[360]

To derive the Massachusetts expected value forecast, the Company stated that it prorated, on a year-to-year basis, the forecasted demand in its regional expected value forecast by the ratio of the forecasted demand in the Massachusetts reference forecast to the

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358 The Company indicated that its Massachusetts reference forecast reflects an average annual growth rate in adjusted peak load of 2.21 to 2.55 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. HO-MN-39, Attachment 7-5) (see Section II.C.4.b.i.(B), below).

359 The Company indicated that its Massachusetts expected value forecast reflects an average annual growth rate in adjusted peak load of 2.50 to 2.83 percent over the 1992-2007 forecast period, depending on which of the Company's three DSM forecasts is used (Exh. HO-MN-39, Attachment 7-5) (see Section II.C.4.b.i.(A), below).

360 The Company stated that, over the last three years of the forecast period, the Massachusetts expected value forecast is the highest forecast, and thus also provides a reasonable high case forecast methodology for that time frame (Exh. HO-MN-50). The Company indicated that the Massachusetts expected value forecast, although only the third highest forecast during the early years of the forecast period, incorporates higher peak load growth that allows it to surpass all forecasts by the end of the forecast period (Exh. HO-MN-39, Attachment 7-5). Specifically, the Massachusetts expected value forecast surpasses the Massachusetts linear regression forecast beginning in 1997 to 1999, depending on which of the Company's three DSM forecasts is assumed, and surpasses the Massachusetts CAGR regression forecast beginning in 2005 under any of the Company's DSM forecasts (id.).

forecasted demand in the reference forecast (Exhs. HO-MN-39, attached exhibit at 3; HO-MN-44). The Company stated that, since the reference forecast and the Massachusetts reference forecast are consistent in terms of methodology and assumptions, it is reasonable to use them for purposes of prorating the expected value forecast (Exh. HO-MN-44).

In addition to presenting the above two Massachusetts demand forecasts based respectively on NEPOOL's deterministic forecasting and NEPOOL's probabilistic forecasting, the Company presented the Massachusetts end year CAGR forecast as a useful alternative to the Massachusetts reference forecast (Exh. HO-MN-39, attached exhibit at 3). The Company indicated that its end year CAGR forecast methodology assumes that Massachusetts adjusted peak load in 2007 will be the same as forecasted by the Massachusetts reference forecast, but utilizes the average annual 1992-2007 compound growth rate underlying that 2007 peak load level to forecast demand for the intervening years (Exhs. HO-MN-39, Attachment 7-5; HO-MN-45).[361] The Company stated that, by assuming a constant growth rate consistent with the long term outcome of the Massachusetts reference forecast, the end year CAGR methodology dampens the short-term pessimism of the Massachusetts reference forecast (Exh. HO-MN-45).[362] The Company added that the

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361 The Company indicated that, to apply the end year CAGR methodology to adjusted peak load, it first derived Massachusetts adjusted peak load values for 1992 and 2007 by adjusting NEPOOL's Massachusetts peak load forecast to reflect EEC's DSM assumptions for those years, and then derived a CAGR trend forecast of Massachusetts adjusted peak load for the intervening years (Exh. HO-MN-39, Attachment 7-5). The Company indicated that its Massachusetts end year CAGR forecast reflects a constant annual growth rate of 2.21 to 2.55 percent, depending on which of EEC's three DSM forecasts is used (id., Exh. HO-MN-45) (see Section II.C.4.b.i.(A), below)

362 As an example of the relatively flat, short-term trend, the Company indicated that its Massachusetts reference forecast projects 1992-1995 increases in adjusted peak load of 1.42 to 1.99 percent, depending on which of EEC's three DSM forecasts is used (Exh. HO-MN-39, Attachment 7-5). In terms of annual MW increments, the Company's Massachusetts reference forecast shows average annual increases in adjusted peak load of 128 MW to 181 MW between 1992 and 1995, depending on which DSM forecast is used, and 148 MW to 200 MW between 1992 and 1997 -- the on-line date of the proposed project (id.). However, indicative of the higher rate of increase in the longer (continued...)

use of a constant annual growth forecast for supply planning purposes would decrease the possibility that prolonged periods of oversupply or undersupply of generating capacity would occur (id.).

The Company stated that it developed its two remaining forecasts -- the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast -- based on performing time series regression analysis of 1974-1991 weather-normalized Massachusetts summer peak load data derived from NEPOOL data (Exh. HO-MN-39, attached exhibit at 3).[363] The Company stated that historic trends in DSM are reflected in the weather-normalized data that underlies the regression equations, and claimed that a moderate to high amount of DSM thus was incorporated in the regression forecasts (Exh. HO-MN-46). The Company indicated that the projected growth in Massachusetts peak load would be 179 MW per year under the linear regression forecast[364] and 2.39 percent per year under the CAGR regression forecast (Exh. HO-MN-39, attached exhibit at 3, Attachments 7-2, 7-5). The Company stated that both regression formats show good statistical results for the 1974-1991 historical data (id.).

The Company asserted that the Massachusetts linear regression forecast represents a reasonable low case, claiming that the Siting Council's West Lynn Decision supports the view that a linear regression forecast constitutes an "approximate minimum" for a long-term

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[362](...continued)
term, the Company's Massachusetts reference forecast shows average annual incremental increases in adjusted peak load of from 271 MW to 308 MW between 1997 and 2007 (id.).

[363] The Company stated that weather-normalized data was not available by state, and that it approximated such data by multiplying NEPOOL's 1974-1991 weather-normalized summer peak load data by the year-to-year ratio of actual Massachusetts summer peak load to actual NEPOOL summer peak load (Exh. HO-MN-39, attached exhibit at 3).

[364] Over the 1992-2007 forecast period, the linear trend corresponds to a CAGR of 1.71 percent (Exh. HO-MN-39, Attachment 7-5).

forecast (EEC Brief at 23-24; Exh. HO-MN-51).[365] The Company also asserted that the Massachusetts CAGR regression forecast, the highest forecast over all but the last three years of the forecast period, represents a reasonable high case over that 1992-2004 period (Exh. HO-MN-50).

(B) DSM Forecasts

The Company stated that it utilized NEPOOL's DSM forecast for Massachusetts, which corresponds to NEPOOL's DSM forecast for New England contained in the reference forecast, to develop a range of DSM forecasts for the Massachusetts need analysis (Exh. HO-MN-39, attached exhibit at 4). Repeating arguments from its regional need analysis (see Section II.C.3.b.i.(B)., above), the Company stated that NEPOOL historically has overforecast DSM, and that, therefore, the Company considers NEPOOL's Massachusetts DSM forecast to be a high case DSM forecast for purposes of the Massachusetts need analysis (id.). Consistent with the regional need analysis, the Company stated that a DSM forecast for Massachusetts which assumes 75 percent of the planned increase in DSM above 1991 levels, as forecast by NEPOOL, would represent a reasonable base case DSM forecast (id.). Similarly, the Company stated that it developed a Massachusetts DSM forecast which assumes 50 percent of NEPOOL's planned increase in DSM for Massachusetts above 1991 levels as a low case DSM forecast (id.).

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[365] Based on the Company's projections of adjusted peak load, the Massachusetts linear regression forecast actually is second highest at the beginning of the forecast period, surpassed only by the Massachusetts CAGR regression forecast (Exh. HO-MN-39, Attachment 7-5). However, depending on which of the Company's three DSM forecasts is assumed, the Massachusetts linear regression forecast is surpassed by the Massachusetts expected value forecast beginning between 1997 and 1999, by the Massachusetts end point CAGR forecast beginning between 1999 and 2003, and by the Massachusetts reference forecast beginning between 2002 and 2005 (id.). In defending its selection of the linear regression forecast as a reasonable low case, the Company stated that forecasts based on the Massachusetts reference forecast rely on overly pessimistic economic assumptions in the short term (Exh. HO-MN-51).

ii. Positions of Intervenors and Company's Response

The Attorney General argued that the Company's Massachusetts demand forecast methodologies are biased upward and thus overstate likely future load growth (Attorney General Brief at 76-86). The Attorney General's witness, Dr. Shakow, presented testimony discussing: (1) deficiencies in the Company's Massachusetts demand forecasts; (2) the Company's failure to consider individual Massachusetts utility forecasts; and (3) results of an alternative "diagnostic" econometric forecast based on multiple regression analysis (Exh. AG-204, at 39-51, attached exhibits DMS-2, DMS-3).

The Attorney General argued that the Company's Massachusetts reference forecast, obtained from NEPOOL, is subject to the same criticisms as the CELT reference forecast used in the Company's regional need analysis (see Section II.C.3.b.ii, above), and noted that NEPOOL itself has disclaimed any intent to present its state-level forecasts for use by individual states in planning state-specific needs (Attorney General Brief at 78). The Attorney General therefore argued that the Massachusetts reference forecast does not provide a reliable base demand case for determining Massachusetts need in this review (id.).

The Attorney General argued that the Massachusetts expected value forecast, like the regional expected value forecast, is derived from NEPOOL's probabilistic analysis, and therefore is marred by ad hoc upward adjustments and unsubstantiated assignments of probability reflected in the high- and low-load forecasts underlying NEPOOL's analysis (id. at 76). The Attorney General, therefore, argued that the Massachusetts expected value forecast does not provide a reliable basis for determining Massachusetts need in this review (id.). NO-COAL also argued that planning to above a 50 percent confidence level has been rejected by NEPLAN, and also is inconsistent with the Supreme Judicial Court Decision (NO-COAL Brief at II-2).[366] Finally, the Attorney General asserted that the Massachusetts

366 NO-COAL argued that, although the Siting Council stated in BECo (Phase 1) (24 DOMSC at 125) that ensuring "adequate and reliable supplies" may warrant planning to above a 50 percent confidence level where cost-effective, the Supreme Judicial Court has determined that ensuring an adequate supply is not the same as providing a necessary supply (NO-COAL Brief at II-2).

expected value forecast shows higher growth rates than every other Massachusetts demand forecast offered by EEC, and thus is an "awkward" choice as the Company's base demand forecast (Attorney General Brief at 76).

The Attorney General argued that EEC offered no evidence to support its use of the ratio of the Massachusetts reference forecast to the regional CELT reference forecast to derive the Massachusetts expected value forecast from NEPOOL's regional expected value forecast (id. at 76-77).[367] The Attorney General also argued that, as in the case of the Company's regional expected value forecast, the Massachusetts expected value forecast for years beyond 1997 reflects inappropriate extrapolation of NEPOOL's 1993-1997 probabilistic forecast results (id. at 78).

The Attorney General argued that the Massachusetts end year CAGR forecast inappropriately incorporates an average long term growth rate to support a time-sensitive need determination (id. at 80). He further argued that, with respect to the years between the first year and the end year, the end year CAGR methodology is not a sophisticated methodology because it abstracts from, rather than incorporates, the NEPOOL 1992 CELT forecast methodology (id. at 81-82).[368] Dr. Shakow testified that the end year CAGR methodology denies the reality of the current recession, which he characterized as a recession that is based on structural factors and that is likely to persist over the next several years (Exh. AG-204, at 44).

The Attorney General also argued that the Massachusetts end year CAGR forecast is biased upward because the Massachusetts reference forecast, itself, is biased upward (Attorney General Brief at 79) (see above, referencing Section II.C.3.b.ii, above).

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367 The Attorney General claimed Mr. La Capra admitted that it would be inappropriate to prorate NEPOOL's high demand forecast to Massachusetts based on the reference forecast ratio (Attorney General Brief, citing, Tr. JH4, at 94).

368 The Attorney General claimed that the 1992 CELT forecast model projects peak load for a particular year based on the accumulated forecast of peak load levels for preceding years, not on any conception of long-term load growth that is separate from the results of the 1992 CELT forecast model (Attorney General Brief at 81).

NO-COAL argued that the 2.4 percent long-term average annual growth rate underlying the Massachusetts reference forecast exceeds long term growth rates recently forecast by BECo and developers of the MASSPOWER project (NO-COAL Brief at II-1).

The Company responded that capacity planning decisions are fraught with uncertainty, and, therefore, the Attorney General's view that such decisions be made in a time-sensitive manner shows a gross misunderstanding of the complicated and uncertain nature of resource planning (EEC Reply Brief at 20-21). The Company maintained that basing planning decisions on a well-developed long term trend is the best way to avoid the extremes of excess capacity and the "far more serious risk" of deficiencies (id. at 21).

The Attorney General argued that the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast represent primitive methodologies with demonstrated theoretical and empirical shortcomings, and, therefore, are inadequate to support a determination of Massachusetts need (Attorney General Brief at 86). Dr. Shakow testified that a major drawback of the Company's use of time series regression forecasts is the implicit assumption that load growth occurs in a highly stable socio-economic environment, leading to an erroneous presumption that social and economic conditions in Massachusetts likely will remain stable over the next 15 years (Exh. AG-204, at 44). The Attorney General argued that, like the end-year CAGR methodology, the Company's time series regression forecasts abstract from the business cycle and associated fluctuations in demand, and, thus, are not useful for determining short-term to mid-term need (Attorney General Brief at 84). With respect to DSM, the Attorney General argued that simple extrapolation of historical peak load trends fails to incorporate a realistic picture of DSM, because formal DSM programs did not appear until very late in the historical regression period (id. at 83-84). Finally, taking issue with the Company's assertion that the West Lynn Decision supports the Company's use of the Massachusetts linear regression forecast as a low case, the Attorney General argued that the linear regression forecast in the West Lynn Decision was based on unadjusted load and included a separate forecast of DSM reductions, and thus differed from the Company's application of the linear regression forecast methodology (id. at 85).

The Company responded that Siting Council precedent supports the use of linear and CAGR regression methodologies to develop alternative forecasts of need (EEC Reply Brief at 21-22).

In addition to raising concerns with the Company's individual demand forecast methodologies, the Attorney General criticized the Company's approach to selecting a range of demand forecasts for its Massachusetts need analysis (id. at 67-76). Specifically, the Attorney General argued that: (1) the Company inappropriately presented a multiplicity of demand forecast methodologies as an indication of forecast sensitivity, instead of presenting a chosen "proper forecasting methodology" with reasonable bandwidths to represent forecast sensitivity based on possible future events; (2) the Company made no serious effort to develop a responsible multiple regression forecast based on econometrics; and (3) the Company failed to investigate how its Massachusetts demand forecasts compare to an aggregation of peak load forecasts prepared by Massachusetts utilities for their in-state service areas (id.).

With respect to use of multiple regression, the Attorney General argued that the Company inappropriately rejected that methodology based on five multiple regression analyses conducted by Mr. La Capra (id. at 73-74). The Attorney General asserted that Mr. La Capra's choice of regression variables posed multicollinearity problems, i.e., the independent variables were correlated with each other, and that such multicollinearity led to poor statistical results which ensured that the Company's multiple regression analyses would not provide plausible forecasts (id. at 74-75).

To demonstrate the feasibility of multiple regression forecasts and provide results of such a forecast, Dr. Shakow presented the following two multiple regression analyses of Massachusetts electricity sales by customer class: (1) an analysis based on a "relatively elaborate array" of up to six independent variables for each class ("elaborate multiple regression"); and (2) an analysis based on a "more basic model" of up to three independent variables for each class ("basic multiple regression") (Exh. AG-204, at 45-48, attached exhibits DMS-2, DMS-3). Dr. Shakow stated that, unlike the Company's multiple regression analyses, his elaborate multiple regression analysis showed good statistical results, including correct signs for all independent variables (id. at 46-47).[369] Dr. Shakow stated that his basic multiple regression forecast indicated that Massachusetts peak load would increase at an average annual rate of 1.47 percent between 1992 and 1998, and 1.33 percent between 1992 and 2007 (id. at 48).

In response, the Company asserted that Dr. Shakow's multiple regression analyses contained several fundamental flaws, including: (1) use of median effective buying income as an independent variable, rather than an average or aggregate measure of personal income; (2) use of erroneously high energy loss factors for adjusting historical energy sales data; and (3) use of historical peak load data that was not weather-normalized (EEC Brief at 24-27). With respect to the choice of an income measure, the Company noted Dr. Shakow's acknowledgement that median effective buying income showed a lower projected rate of average annual growth than aggregate disposable personal income -- 1.1 percent versus 1.8 percent (id. at 26; Tr. JH7, at 36-37). The Company argued that, given the admitted flaws, the Siting Board should reject the use of Dr. Shakow's multiple regression analyses for assessing Massachusetts need (EEC Brief at 27).

With respect to comparison with Massachusetts utility forecasts, the Attorney General cited three utility forecasts that show 1992-1997 growth rates of from 0.97 percent to 1.39 percent and longer term growth rates of from 0.99 percent to 1.79 percent, and claimed such growth rates are substantially lower than those reflected in Mr. La Capra's Massachusetts demand forecasts (id. at 70-71). The Attorney General asserted that a fourth utility projects no need for new capacity until 2002 (id.).

The Company responded that it is preferable to use an integrated state forecast, which is based on common assumptions, rather than rely on a number of individual utility forecasts, which are filed at different times and based on varying assumptions (EEC Reply Brief at 13). The Company also argued that Massachusetts utility forecasts are not all available, leaving

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369 The Attorney General stated that the elaborate multiple regression analysis was satisfactory for the purpose of indicating the signs of coefficients, but was not suitable for forecasting because the number of degrees of freedom was low (Exh. AG-204, at 47).

"missing components ... far bigger than the growth rate you're trying to measure," and that, even where available, most such forecasts have not yet been approved by the DPU (id.).

iii. Analysis

As described above, the Company utilized five demand forecast methodologies for its Massachusetts need analysis, of which two -- the Massachusetts reference forecast and the Massachusetts expected value forecast -- correspond to methodologies used in the regional need analysis. The Company and other parties generally adopted positions regarding the Massachusetts reference forecast and the Massachusetts expected value forecast matching those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.C.3.b.iii, above.

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

In regard to the expected value forecast,[370] the Attorney General did raise one methodological concern applicable only to the Massachusetts need analysis -- a criticism of the Company's use of the regional and Massachusetts reference forecasts to develop a ratio for prorating results of the regional expected value forecast to derive the Massachusetts expected value forecast. As acknowledged by the Company in relating NEPOOL's reference forecast to its high case forecast, the Attorney General correctly argues that the ratio of Massachusetts peak load to regional peak load could vary for different confidence levels in the probability assessment. However, the record contains no evidence that the Company's prorating approach resulted in a particular bias, upward or downward, in the Massachusetts expected value forecast.[371]

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[370] In criticizing the Massachusetts expected value forecast, NO-COAL argued that planning to greater than a 50 percent confidence level is inconsistent with NEPLAN criteria underlying the CELT forecast and with the holding in the City of New Bedford decision that an "adequate" energy supply is not the same as a "necessary" energy supply. As a preliminary matter, the Siting Board notes that NO-COAL's arguments would apply equally to the Company's expected value forecast in the regional need analysis. In either context, the Siting Board does not agree that the Company's expected value forecasts are invalidated based on NO-COAL's arguments. Regarding the identified recognition by NEPLAN of a 50 percent confidence level in developing CELT forecast, the Siting Board notes that NEPOOL prepares a probabilistic forecast as part of its resource assessment in order to provide an alternative forecasting perspective from, not a substitute for, the NEPOOL deterministic forecast, which incorporates the NEPLAN criteria referenced by NO-COAL. Thus, a forecast based on probabilistic concepts is not constrained by criteria underlying the CELT forecast. Regarding the cited distinction between the terms "necessary" energy supply and "adequate" energy supply, we note that the Siting Board has reviewed the meaning of those terms in Section II.C.2.b., above. Based on our interpretation of the meaning of the terms "necessary" and "adequate," City of New Bedford does not invalidate Siting Council precedent indicating that use of confidence levels greater than 50 percent may be appropriate for reliability purposes.

[371] The Siting Board notes that the Attorney General did not suggest an alternative prorating approach that would be more accurate and still provide a practical means for the Company to adapt NEPOOL's expected value analysis to address Massachusetts need.

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

The remaining three Massachusetts demand forecast methodologies -- the end year CAGR forecast, the linear regression forecast and the CAGR regression forecast methodologies -- do not represent counterparts to forecast methodologies included in the Company's regional need analysis. Thus, we address below the positions of the parties regarding those Massachusetts demand forecast methodologies.

With respect to the Massachusetts end-year CAGR forecast, the Company claimed that the long-term CAGR trend dampens the short-term pessimism of the Massachusetts reference forecast, while the Attorney General countered that the end-year CAGR methodology inappropriately abstracts from the 1992 CELT forecast methodology and thereby denies the reality of the current recession. The Attorney General also noted that the concerns he raised regarding long-term upward biases in the underlying 1992 CELT forecast methodology apply to the Company's end-year CAGR forecast, and NO-COAL argued that the Company's long-term CAGR trend is high compared to expectations of a Massachusetts utility and a NUG developer.

With regard to the Attorney General's concerns about reliance on a long-term trend, the Siting Board agrees that it is important to consider some forecasts that reflect cyclical influences. In addition, the Siting Board recognizes that, by factoring out short-term fluctuations that may be a source of disagreement among different forecasters, the Massachusetts end-year CAGR forecast inevitably loses much of any robustness or sophistication that is present in the underlying forecast. However, the long-term trend underlying a recognized cyclical forecast also is an important consideration, and we do not agree with the Attorney General that forecasts which factor out short-term cycles should be totally excluded from the analysis.

With regard to intervenors' concern that the long-term CAGR trend is high, the Siting Board notes there are some technical considerations that warrant comment. First, the

Company's forecast results show that the Massachusetts end-year CAGR forecast is higher than the Massachusetts reference forecast for the entire 15-year span of the forecast period, excepting the end year itself. While the record does not indicate the reason for the Company's choice of the forecast end year as the basis of its CAGR methodology, we recognize the intuitive logic of using the end year to represent the long term.

However, we note that the Company defended the CAGR methodology as a means to avoid both underforecasting and overforecasting. As mentioned, the Company applied the CAGR methodology based on the end year 2007, and thereby implicitly incorporated an assumption that the underlying Massachusetts reference forecast had erred only on the side of underforecasting load over the 1992-2007 period. Further, given that the Massachusetts reference forecast shows its most rapid growth over the latter ten years of the forecast period -- with annual increases in Massachusetts peak load ranging from 271 MW to 308 MW per year -- the Company's forecast results are potentially sensitive to its choice of a representative long-term forecast year for purposes of developing the CAGR trend. EEC might have provided a more balanced basis to develop the long term trend of its forecast if it had used a forecasted load from the Massachusetts reference forecast that was representative of a range of later years in the forecast period, rather than just the end year.

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

With regard to the comparative forecasts cited by NO-COAL, there is no indication that such forecasts were developed at a comparable time or for a comparable area, relative to the Company's Massachusetts end year CAGR forecast. Thus, NO-COAL's argument does not provide a basis to reject the Company's forecast.

Overall, although the Company may have developed an unrepresentatively high long term trend by basing its Massachusetts end year CAGR forecast solely on NEPOOL's Massachusetts load forecast for the end year 2007, the Company was conservative in its choice of a CAGR trend rather than a linear trend. Therefore, on balance, the record does not support a conclusion that the Company's end year CAGR methodology produced a trend-based forecast that is biased upward, as argued by the Attorney General and NO-COAL.

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

With regard to the Massachusetts linear regression forecast and the Massachusetts CAGR regression forecast, the Company maintains that both time series regression formats provided good statistical results and are consistent with Siting Council precedent, while the Attorney General criticizes the time series forecasts as a primitive approach that abstracts from the business cycle and is not suitable for determining need in the short or intermediate term. In two additional areas of contention, the Company argues that (1) its time series regression forecasts adequately capture a moderate to high amount of DSM and (2) its linear regression forecast represents a minimum forecast based on Siting Council precedent, while the Attorney General disputes both points.

As argued by the Company, the Siting Council previously accepted time series regression forecasts for purposes of establishing need. West Lynn Decision, 22 DOMSC at 27-32, 34. We note that, here, only two of the Company's 11 demand forecasts reflect time series regression, given that the Company did not separate out DSM as an adjustment to load for its linear and CAGR regression forecasts.

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

With regard to DSM, the Siting Board questions the Company's assertion that its time series regression analyses, based on a 1974-1991 historical period, can adequately capture current rates of DSM implementation. As argued by the Attorney General, formal utility-sponsored DSM programs did not appear until late in the historical period used in the Company's regression analyses. Thus, a majority of the peak load data points in the Company's regression analyses cannot reflect the annual amounts of DSM implementation observed in recent years. Therefore, unless annual amounts of DSM implementation are significantly smaller over the forecast period than in recent years, the Company's time series regression forecasts likely do not fully capture DSM trends.

Finally, the Siting Board disagrees with the Company's position that Siting Council precedent supports a conclusion that the Company's linear regression forecast is an "approximate minimum" forecast. First, as argued by the Attorney General, the extrapolated linear regression trend in the West Lynn Decision review was adjusted for DSM in order to derive a demand forecast, as distinct from EEC's linear regression forecast approach which ignored DSM. Second, the Siting Council's holding in the West Lynn Decision was premised on an absence of theoretical factors warranting consideration of lower forecasts. Here, the Attorney General's case concerning possible recent and ongoing structural changes in the New England and national economies, although supported by scant evidence, represents to a limited degree the type of theoretical factor that potentially could warrant consideration of a slower long term growth trend than reflected in a linear regression analysis of past peak load levels.

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

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

The Attorney General also criticizes the Company's overall Massachusetts demand analysis for (1) its failure to successfully incorporate a demand forecast methodology based on multiple regression, and (2) its failure to compare forecasts of Massachusetts peak load to an aggregation of peak load forecasts prepared by Massachusetts utilities.

Regarding multiple regression, the Siting Board agrees with the Attorney General that facility applicants should seriously pursue that approach as an alternative forecast methodology for purposes of regional or Massachusetts need analyses. However, the examples of multiple regression forecasts provided by the Attorney General for diagnostic purposes contained serious flaws -- most notably the use of an inappropriate personal income variable.

We note the Attorney General did not intend his multiple regression analyses to serve as alternative demand forecasts in this review, instead characterizing them as diagnostic models. Given the flaws in the Attorney General's models, we conclude that they not only are unreliable as a basis for assessing need in this review, but also fall short of establishing that the Company was remiss in its inability to develop a statistically acceptable multiple regression model.

Regarding use of utility forecasts, the Siting Board agrees with the Company that, given inconsistencies in utility forecast timing, methodology and regulatory review, it would be impractical to attempt to develop a statewide forecast based on aggregating results from available Massachusetts utility forecasts. However, the Attorney General is correct that utility forecasts provide a valuable check in reviewing results of regional or statewide forecast models, such as those included in the Company's need analysis. Such comparisons do not, in and of themselves, invalidate the results of models provided by the Company that may show significantly greater future demand. However, the evidence of lower utility expectations for future demand inevitably does provide important corroboration for the cautions and qualifications that the Siting Board has raised in its review, above, of some of the Company's higher demand forecasts.

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

NEPOOL's high and low DSM cases are not disaggregated by state. Thus, to adjust the Company's high and low DSM forecasts to be consistent with the regional need analysis, it is necessary to prorate NEPOOL's high and low DSM cases to Massachusetts based on the ratio of the adjusted base DSM forecasts in the Massachusetts and regional analyses.[372]

Accordingly, consistent with its findings in the regional need analysis, the Siting Board finds that (1) an adjustment of the Massachusetts base DSM forecast by 8.4 percent of the increment over 1992 levels is reasonable for purposes of this review; (2) the Company's Massachusetts high DSM forecast should be adjusted to represent Massachusetts' prorated

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[372] With respect to the demand forecasts incorporating the end-year CAGR methodology, the Siting Board adjustments to DSM require recalculation of the CAGR trend based on new values for DSM and resultant peak load in 2007 (see Section II.C.4.b.i.(A), above). The new peak load values for 2007 with the adjusted DSM values are 12,402 MW under the base DSM forecast, 12,187 MW under the high DSM forecast and 12731 MW under the low DSM forecast. The new CAGRs are 2.246 percent under the base DSM forecast, 2.126 percent under the high DSM forecast and 2.425 percent under the low DSM forecast.

share of the 1992 CELT high DSM case, and (3) the Company's Massachusetts low DSM forecast should be adjusted to represent Massachusetts' prorated share of the 1992 CELT low DSM case.

c. Supply Forecasts

i. Description

The Company stated that it developed base, high and low supply forecasts for Massachusetts which are consistent with the Company's updated regional supply forecasts (Exh. HO-MN-39, attached exhibit at 4) (see Section II.C.3.c.i., above). The Company stated that it developed its base Massachusetts supply forecast based on the 1992 CELT forecast of committed capacity that is owned or contracted by Massachusetts utilities, regardless of location, but excluded committed capacity in planned NUG projects not yet under construction (id. at 5).[373,374]

With respect to interstate utilities supplying Massachusetts, the Company stated that the committed capacity of each such utility system was prorated to its Massachusetts service area based on the ratio of Massachusetts to systemwide summer peak load in 1991 (id.).[375]

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373 The Company stated that it obtained Massachusetts committed capacity information directly from the 1992 CELT Report, except that it made adjustments based on other sources in order to: (1) reflect updated plant retirements and additions; (2) identify Massachusetts' 598 MW share of the Hydro-Quebec contract; and (3) identify Massachusetts' share of the PASNY allocations, amounting to 63 MW from 1995 to 1997 and 71 MW from 1998 to 2007 (Exh. HO-MN-39, attached exhibit at 5, Attachments 7-6, 7-7, 7-8; Exh. SB-JH-RR-11R).

374 The Company stated that, if Massachusetts supply were based on nameplate capacity of power plants located in Massachusetts, the base case would reflect approximately 1,200 MW less capacity, resulting in earlier or larger Massachusetts need (Exh. HO-MN-39, attached exhibit at 4).

375 The Company stated that the 1991 ratios for the three interstate utility systems -- New England Electric System ("NEES"), Eastern Utilities Associates ("EUA") and Northeast Utilities ("NU") -- are almost identical to the average projected ratios for these systems (Exh. HO-MN-53). The Company presented utility forecast information indicating that, between 1991 and 2001, the ratio of Massachusetts to systemwide summer peak load will decrease by 0.023 and 0.004 for NEES and NU, respectively, but will increase by 0.008 for EUA (id., attachment MN-53(d)).

Consistent with its regional need analysis, the Company indicated that it assumed a 22.5 percent reserve margin applicable to overall supply resources of Massachusetts utilities (id. at 7).

To develop the Massachusetts high supply case, the Company stated that it included 50 percent of the total capacity of uncommitted projects included by Massachusetts utilities in the 1992 CELT report, as well as 50 percent of Massachusetts share of a possible extension of the Hydro-Quebec contract beyond 2000 (id. at 5-6). The Company noted that it made no adjustment for the possibility that portions of two projects in the high case -- BECo's 306 MW Edgar project and the 150 MW Taunton Energy Center project -- could be sold to non-Massachusetts utilities (id.).

To develop the low supply case, the Company assumed the unavailability of the Pilgrim unit 1 nuclear facility, and stated such a case was more than an academic possibility based on the Pilgrim facility's history of operating problems (id. at 5). The Company stated that its Massachusetts low supply case thus is consistent with its regional low supply case, which was based on the loss of a representative average nuclear unit rather than a specific nuclear unit or series of units (id.) (see Section II.C.3.c.i., above).

In addition to presenting base, high and low Massachusetts supply forecasts, the Company presented a Massachusetts contingency analysis based on a set of contingency scenarios similar to, but more limited than, that utilized in the regional need analysis (id. at 6-7) (see Section II.C.3.c.i, above). The Company indicated that it identified nine Massachusetts contingencies corresponding to nine of the 11 regional contingencies (id.).[376] The Company presented these nine Massachusetts contingency supply forecasts, based on adjusting the Massachusetts base supply forecast to reflect each of the nine Massachusetts contingencies (id.).

[376] The two regional contingencies not included in the Massachusetts need analysis are (1) the addition of 40 percent of planned but uncommitted NUGs, and (2) the addition of 80 percent of planned but uncommitted NUGs (Exh. HO-MN-39, attached exhibit at 6-7).

ii. Positions of the Intervenors and Company's Response

Consistent with his position regarding the Company's regional supply forecasts, the Attorney General argued that the Company developed Massachusetts supply forecasts and contingencies that understate the future supply likely to be available to Massachusetts utilities (Attorney General Brief at 86-88, 90-95). The Attorney General also argued, again repeating a position he took regarding the regional need analysis, that the Company assumed an unreasonably high reserve margin of 22.5 percent in its base, high and low forecasts and all but two contingency cases (id. at 88-90).

The Attorney General referred to 111 MW of uncommitted NUG capacity that is existing or under construction in New England -- specifically, the uncommitted portions of the MASSPOWER, Enron and AES Thames projects -- and argued that, as in the regional need analysis, the Company inappropriately omitted that capacity from its base supply case in the Massachusetts need analysis (id. at 86-87). The Attorney General further argued that, given the Company's position that need will arise earlier in Massachusetts than New England as a whole, it is reasonable to assume for purposes of the Company's need analysis that all 111 MW of said NUG capacity will supply Massachusetts utilities (id.).

The Company responded that the record provides no basis to determine that the above projects will represent a cost-effective supply for a Massachusetts utility rather than another New England utility (EEC reply Brief at 25). The Company reiterated that its base supply case represents only committed capacity, owned or contracted, and added that the uncommitted NUG capacity is sufficiently captured as a Massachusetts supply contingency (id.).

The Attorney General argued that the Massachusetts high supply forecast, like its counterpart in the regional need analysis, is overly pessimistic in assuming that only 50 percent of planned but uncommitted utility capacity will be available (id. at 53, 91).[377] He

[377] The Attorney General noted the significance of including 100 percent of the largest such planned unit -- the 306 MW Edgar project -- as part of the Company's high supply forecast, observing that, if the Company's Massachusetts reference forecast (continued...)

also argued that the Massachusetts low supply forecast should be disregarded because it assumes the unavailability of the Pilgrim unit 1 -- a possibility that is too remote to warrant consideration in a need-for-power analysis (id. at 91).

With respect to the Company's supply contingencies, the Attorney General argued that the Company should have assumed life extensions for 100 percent of planned Massachusetts retirement capacity, rather than 25 percent, given that only one Massachusetts unit is scheduled for retirement (id. at 92). He also argued that, given the Company's position that Massachusetts need arises earlier than regional need, the Company should have assumed that (1) all of the contingency NUG capacity for New England will be available for Massachusetts, and (2) none of the contingency reduction in Hydro-Quebec capacity for New England will affect Massachusetts (id. at 93-95). NO-COAL argued that the Company's selection of Massachusetts contingencies represents a "stacked deck," given the inclusion of such assumptions as the 1993 shut down of the Pilgrim facility and the curtailing of purchases from Hydro-Quebec (NO-COAL Brief at II-1).

With respect to the Company's prorating of future-year interstate utility capacity to Massachusetts, the Attorney General argued that the Company inappropriately utilized ratios of in-state to systemwide peak load as forecast by the individual utilities (Attorney General Brief at 87-88). He argued that, instead, the Company should have used higher ratios to reflect the fact that EEC's forecasted rate of growth in peak load for Massachusetts exceeds that forecasted by the interstate utilities for their respective systems (id.).

iii. Analysis

As described above, the Company developed base, high and low supply forecasts and additional contingency forecasts for its Massachusetts need analysis that are in large part consistent with those used in the regional need analysis. The Company and other parties

[377](...continued)
were assumed in conjunction with the high supply forecast including all of the Edgar project, the resultant Massachusetts supply deficiency in 1998 would be 221 MW, rather than over 300 MW as forecast by the Company under its high supply forecast assumptions (Attorney General Brief at 91-92, citing Exh. HO-JH-RR-9).

generally adopted positions regarding the Massachusetts supply forecasts and contingency forecasts matching those adopted with respect to the corresponding forecasts in the regional need analysis. The Siting Board reviewed those positions in Section II.C.3.c.iii, above.

Consistent with its findings regarding assumed reserve margins in the regional need analysis, the Siting Board finds that the Company's reserve margin for the years 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.

Further, in its review of the regional need analysis, the Siting Board adjusted the Company's high supply forecast to include 66 MW of uncommitted capacity of NUG projects in the region that are existing or under construction. For purposes of the Massachusetts need analysis, it is reasonable to prorate the 66 MW adjustment based on the ratio of the Massachusetts reference forecast to the regional reference forecast. Under that approach, Massachusetts' prorated share of the 66 MW adjustment is 30 MW in each of the years 1997 through 2000. Accordingly, the Siting Board finds that the Massachusetts high supply forecast should be adjusted to include 30 MW of the uncommitted capacity of NUG projects that are existing or under construction.

Among issues that relate only to the Massachusetts need analysis, the Attorney General argues that the outcome of the Company's overall need analysis, specifically the "high" Company forecasts of Massachusetts demand and the earlier occurrence of Massachusetts need relative to regional need, invalidates assumptions the Company made in prorating interstate utility supply and possible future regional capacity changes to develop its Massachusetts supply forecasts. The Attorney General also argues that the Company should not have hypothesized partial realization of potential life extension as a Massachusetts contingency, given the presence of only one candidate facility in Massachusetts. Finally, both the Attorney General and NO-COAL suggest that the Company's low supply forecast, hypothesizing the loss of the Pilgrim unit, is a remote possibility.

Regarding invalidation of supply forecast assumptions by forecast results, the Attorney General appears to take the forecast results out of their logical context. First, it is reasonable that a "higher" load in the Massachusetts portion of an interstate utility's service area would be accompanied by a similarly higher load in the non-Massachusetts portion of the utility's service area, reflecting economic influences on a regional or national level. Under that scenario, supply allocation based on the utility's own load forecast still would be reasonably accurate. Second, the Attorney General's position regarding allocation of future capacity changes apparently assumes that the underlying supply options will be offered in years when there is Massachusetts need but not regional need, and that during such years all non-Massachusetts utilities will be uniformly in surplus. While earlier Massachusetts need may suggest that Massachusetts utilities will be more aggressive in obtaining or retaining supplies, there is no basis to conclude that the extreme adjustments suggested by the Attorney General are warranted.

With respect to the Attorney General's concern regarding the supply contingency based on a partial life extension, we note that such discounting is an accepted method of reflecting uncertainty or probability, and is appropriate for a contingency analysis. With respect to the loss of Pilgrim, we note, as in our review of the regional need analysis, that the Company might have discounted its hypothesized loss of that nuclear unit to better reflect the limited probability of such loss. Nonetheless, loss of Pilgrim for an unusually long period was once experienced, and Massachusetts utilities own significant shares of other nuclear units which also potentially could be lost for long periods. Thus, the Massachusetts low supply forecast is reasonably consistent with the regional low supply forecast, and the record does not support a rejection or adjustment of the Massachusetts low supply forecast.

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

Further, consistent with its findings in the regional need analysis, the Siting Board finds that the Company's Massachusetts supply contingency analysis provides an acceptable basis for assessing the potential range of Massachusetts utility capacity positions that might arise over the forecast period.

d. Need Forecasts

i. Description

The Company presented 33 need forecast scenarios based on a comparison of its 11 demand forecasts, derived from the five methodologies and the three DSM forecasts, with its three supply forecasts, base, high and low (Exhs. HO-MN-39, Attachment 7-12, HO-JH-RR-11R). Comparing all the Company's demand and supply forecasts, the cumulative number and percentage of need forecasts that demonstrate a need for at least 300 MW of capacity would be: (1) 30 need forecasts, 90.9 percent, in 1997; (2) 33 need forecasts, 100 percent, in 1998 and beyond (id.). The Company indicated that comparison of its base demand forecast -- the Massachusetts expected value forecast with EEC's base DSM assumptions -- and its base supply forecast -- the 1992 CELT capacity forecast with updated information -- showed a need for over 300 MW in the early years of the proposed project, specifically: (1) 955 MW in 1997; (2) 1,301 MW in 1998; (3) 1,659 MW in 1999; and 2004 MW in 2000 (id.). See Table 7.

EEC also presented 99 additional need cases based on (1) adjusting the base supply forecast to reflect each of the Company's nine contingencies which would increase or decrease supply, and (2) comparing those nine adjusted supply forecasts with the 11 demand forecasts ("need contingency cases") (id.). Considering the Company's need contingency cases together with its need forecasts, EEC presented a total of 132 Massachusetts need cases (id.). The Company provided a summary of the results of its overall Massachusetts need analysis which indicated that the cumulative number and percentage of need cases that demonstrate a need for at least 300 MW of capacity would be: (1) 124 cases, 93.9 percent, in 1997; (2) 132 cases, 100 percent, in 1998 and beyond (id.).

The Company indicated that 72 of its Massachusetts need cases correspond to need need cases in the Company's regional need analysis (Exh. HO-RR-137). The Company provided a summary of results which indicated that the cumulative number and percentage of such need scenarios that demonstrate a need for at least 300 MW of capacity would be:

(1) 64 cases, 88.9 percent, in 1997; (2) 72 cases, 100 percent, in 1998 and beyond (id., Exh. HO-JR-RR-11R). Comparing said results to the corresponding results for the regional need analysis -- (1) 21 cases, 29.2 percent, in 1997, (2) 48 cases, 66.7 percent, in 1998 -- the Company concluded that its analysis demonstrates that need will arise earlier in Massachusetts than in New England as a whole (Exh. HO-RR-137).

The Company also presented two sets of additional calculations of Massachusetts need in response to requests of the Siting Board, including: (1) alternative need calculations for most of the Company's need cases, based on assuming a 21 percent reserve requirement instead of a 22.5 percent reserve requirement in the years 1998, 1999, 2000 and 2001;[378] and (2) with respect to the three need forecasts that reflect high DSM and base supply, alternative need calculations based on assuming the DSM levels in NEPOOL's high DSM forecast as an alternative to the high DSM levels in the Company's analysis (Exhs. HO-JH-RR-11, HO-JH-RR-12). EEC stated that neither the change in assumed reserve margin nor the change in assumed high DSM levels significantly affects the timing of the first year of continuous need in the Massachusetts need analysis (id.).

With the change in assumed reserve margin, the Company's analysis indicated that the first year of continuous need for at least 300 MW would be one year later -- 1999 instead of 1998 -- for one of the need forecasts, and the cumulative number and percentage of Massachusetts need forecasts that demonstrate need for at least 300 MW would be 32 forecastss, 97.0 percent, in 1998 (Exh. HO-JH-RR-11).[379] The Company further indicated

378 The Company provided recalculations for 110 need scenarios, including all 33 need forecast scenarios and 77 of the need contingency scenarios (Exh. HO-JH-RR-11). The remaining 22 need contingency scenarios involve contingencies that already reflect higher or lower reserve margins, and thus were not included in the requested recalculations (id.).

379 The Company's analysis also indicated that, assuming a 21 percent reserve margin, the first year of continuous need for at least 300 MW would be one year later -- 1999 instead of 1998 -- for one of the need contingency scenarios (Exh. HO-JH-RR-11). Considering the need forecast scenarios and need contingency scenarios together, the cumulative number and percentage of Massachusetts need scenarios that demonstrate need for at least 300 MW would be 130 scenarios, 98.5 percent, in 1998 (id.).

that, with the 21 percent reserve margin, comparison of its Massachusetts base demand forecast and its Massachusetts base supply forecast showed the following need levels, still over 300 MW, in the early years of the proposed project: (1) 955 MW in 1997; (2) 1,144 MW in 1998; (3) 1,497 MW in 1999; and 1,838 MW in 2000 (id.)

The Company indicated that, with the alternative high DSM levels obtained from NEPOOL's high DSM forecast, its high DSM forecast would be only marginally higher -- for example, 42 MW higher in 1997 (Exh. HO-JH-RR-12). The Company further indicated that, assuming its base supply forecast in conjunction with the alternative high DSM levels, the first year of continuous need for at least 300 MW would be 1998 instead of 1997 under the Massachusetts reference forecast, but would continue to be earlier than 1997 under the Massachusetts expected value forecast and the Massachusetts end year CAGR forecast (id.).

ii. Analysis

As noted above, in considering the Company's demand and supply forecasts, the Siting Board has adjusted: (1) the Company's Massachusetts base DSM forecast to reflect discounting of the 1992 CELT DSM levels by 8.4 percent of the increment over 1991 levels; (2) the Company's Massachusetts high DSM forecast to reflect the NEPOOL high DSM case; (3) the Company's Massachusetts low DSM forecast to reflect the NEPOOL low DSM case; (4) the Company's Massachusetts high supply forecast to include the 30 MW of uncommitted capacity of NUG projects that are existing or under construction; and (5) the Company's assumed reserve margin of 22.5 percent to reflect lower levels after 1996, specifically 22 percent for 1997, 21.5 percent for 1998, 21 percent for 1999, and 20 percent for 2000.

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

Separating out the forecast methodologies as described above, the number of need forecasts that demonstrate a need for at least 300 MW in each year, from 1997 through 2000, is as follows:

Forecast	1997	1998	1999	2000
Massachusetts reference forecast (9 cases)	4 (44%)	7 (78%)	9 (100%)	9 (100%)
Alternative Massachusetts demand forecasts (24 cases)	23 (96%)	24 (!00%)	24 (100%)	24 (100%)
Total (33 cases)	27 (82%)	31 (94%)	33 (100%)	33 (100%)

The capacity positions under the Massachusettts need forecasts, as adjusted, are shown in Table 8. Considered with the Massachusetts base DSM forecast, and the Massachusetts base supply forecast: (1) the Massachusetts reference forecast shows a need for 288 MW in 1997, and 553 MW by 1998; (2) the Massachusetts end-year CAGR forecast shows a need for 612 MW by 1997; (3) the Massachusetts expected value forecast shows a need for 785 MW by 1997; (4) the Massachusetts linear regression forecast shows a need for 921 MW by 1997; and (5) the Massachusetts CAGR regression forecast shows a need for 1,451 MW by 1997.

In sum, 27 of the 33 Massachusetts need forecasts, including the 24 need forecasts that incorporate alternative Massachusetts demand forecast methodologies, show a need for at least 300 MW in 1997, 31 show a need for at least 300 MW in 1998, and 33 show a need for 300 MW in 1999 and 2000. However, only four of the nine need forecasts that incorporate the Massachusetts reference forecast show a need for at least 300 MW in 1997, seven such forecasts show a need for at least 300 MW in 1998 and all show a need for at least 300 MW in 1999 and 2000.

Accordingly, based on the foregoing, the Siting Board finds a need for 300 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1998. The Siting Board further finds that the Company's need analysis, including its need forecasts and contingency cases, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 300 MW of additional capacity clearly will occur earlier than New England's need for same.

5. Findings and Conclusions 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);
- 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 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 (pp. 253-254);
- 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. 258);
- 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. 258);
- 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. 259);
- 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 (pp. 256-260);
- a need for 300 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1998 (p. 264); and
- that the Company's need analysis, including its need forecasts and contingency cases, as adjusted, for Massachusetts and New England, demonstrate that Massachusetts' need for 300 MW of additional capacity clearly will occur earlier than New England's need for same (p. 264).

The Siting Board has found that there will be a need for 300 MW or more of additional energy resources in New England for reliability purposes beginning in 2000.

Further, the Siting Board has found that there will be a need for 300 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in 1998. Based on the foregoing, the Siting Board has found that the Company's need analyses demonstrate that Massachusetts' need for 300 MW of additional capacity clearly will occur earlier than New England's need for same. Given the demonstration of earlier need in Massachusetts than New England, it is clear that, for all years in which there will be a regional need for the proposed project, i.e., for the years 2000 and beyond, said project would provide a necessary energy supply for the Commonwealth.

The Siting Board noted above that an applicant could establish that a regional capacity surplus might not be available to meet a Massachusetts capacity deficiency as a result of transmission or other reliability constraints (see Section II.C.2.d). Further, in that Section, the Siting Board noted that an applicant could establish that reliance on a regional capacity surplus would be contrary to providing a necessary energy supply at the lowest possible cost with least environmental impact. This is the first case in which this element of the standard of review has been addressed. Thus, in this case, a record on this issue has not been developed. The record shows that for the years 2000 and beyond there is a need of 300 MW or more for both Massachusetts and the region. However, the record is unclear regarding the ability of Massachusetts utilities to acquire surplus supplies from out-of-state providers in years in which there is a Massachusetts deficiency of 300 MW or more and a regional deficiency of less than 300 MW or a regional surplus. Therefore, based on the record, the Siting Board is unable to determine that the proposed project is needed to provide a necessary energy supply for the Commonwealth prior to the year 2000.

The Siting Board notes that, 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 payments for at least 75 percent of the proposed project's electric output, and (2) signed PPAs which include capacity payments with Massachusetts customers for at least 25 percent of the proposed project's electric output which is the result of a competitive resource solicitation process beginning in 1993 or beyond and which is approved pursuant to G.L. c. 164, § 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.

D. Conclusions on the Proposed Project

Based on the record in this proceeding, the Siting Board has found that the Company has established that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. Further, the Siting Board has found that at such time that 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.

III. THE SITING BOARD'S ANALYSIS/RESPONSE TO OTHER ISSUES IDENTIFIED BY THE COURT

As noted in Section I.A.3, above, the Court remanded the EEC Decision to the Siting Council for reconsideration of EEC's application consistent with the Court's opinion. City of New Bedford at 490. In this section, the Siting Board specifically addresses those "Other Issues Which May Arise On Remand" which were identified by the Court. Id. at 489-491. Certain of these issues have been addressed above in support of the Siting Board's analysis of the proposed project, and, therefore, will only be summarized here.

A. The Commonwealth's Energy Supply

In the EEC Decision, the Siting Council found that "New England needs at least 300 MW of additional energy resources for reliability purposes beginning in 1995 and beyond." 22 DOMSC at 267. In City of New Bedford, the Court stated that "[b]ecause the [Siting Council's] statute mandates a 'necessary energy supply for the *commonwealth*,' this finding is inadequate (emphasis added)." 413 Mass. at 489. This issue was addressed in detail in Section II.C.2, above. In that section the Siting Board set out its standard of review for need for non-utility generating facilities. Specifically, the Siting Board stated that:

> [i]n cases where a non-utility developer seeks to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board requires the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPA's. 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.

With this standard, the Siting Board requires a showing that additional energy resources are needed in Massachusetts and that proposed project will provide a necessary energy supply for the Commonwealth.[380]

[380] In Section II.C.5, the Siting Board found that EEC had established that proposed project will provide a necessary energy supply for the Commonwealth.

B. New Power To Be Produced At The Lowest Possible Cost

In City of New Bedford, the Court stated that, although the Siting Council gave conditional approval to the proposed project and withheld a final finding on cost until further data were submitted, the Siting Council failed to explicitly state its final approval was conditioned on submission of the missing data. 413 Mass. at 489. The Court also stated that "[a] finding that the new power would be produced at the lowest possible cost is necessary to conform to the council's legislative mandate."

The Siting Board acknowledges that such an explicit statement was omitted from the EEC Decision. In the EEC Decision, the Siting Council noted that the Company's next step toward a final approval would be the submission of required information. 22 DOMSC at 223, n.236. In that footnote, the Siting Council indicated that a failure on the part of the Company to establish that environmental impacts would be adequately minimized would lead to a rejection of the petition. Id. The footnote inadvertently omitted any reference to cost.

The Siting Council addressed the cost issue in the EEC Compliance Decision. In that decision, the Siting Council found that EEC had complied with the conditions in the EEC Decision that required the Company to provide additional information relative to environmental impacts. EEC Compliance Decision, 25 DOMSC at 318, 329, 360. The Siting Council then proceeded to analyze the information provided by the Company and, subject to various directives in that decision, found that the cost estimates associated with the proposed facility were minimized consistent with the mitigation of environmental impacts.[381] Id., 25 DOMSC at 318, 348, 368. The Siting Board then concluded from this balancing that the proposed facility would provide energy at the lowest possible cost consistent with the minimization of environmental impacts at that facility. Id., 25 DOMSC at 372.

The Siting Board notes that the actual argument of CNB on appeal was that the Siting Council failed to make a finding that the power would be produced at the lowest possible

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[381] The Siting Board notes that in City of New Bedford, the Court indicated that "the statutory balance involves weighing minimum environmental impact and cost." 413 Mass at 486.

cost to the rate payers (emphasis added). City of New Bedford, 413 Mass. at 489. The Siting Board notes that such a finding would be possible only if all power from a proposed facility were under contract at the time that the developer sought Siting Board approval to construct. However, a non-utility developer who petitions the Siting Board for approval to construct a bulk generating facility may do so at a time prior to completing the marketing of its power (see n. 271, above). In many cases, a non-utility developer is unable to market some or all of its power prior to approval of its petition due to the reluctance of utilities to expend resources negotiating PPAs with projects that may never be approved. Without signed and approved PPAs, the Siting Board is unable to determine whether the contract price is, in fact, at the lowest possible cost to ratepayers.

The Siting Board can, however, determine (1) whether a proposed project could provide power at a cost below a range of utility avoided costs for the area that would likely be serviced by the proposed facility; (2) whether the cost estimates associated with a proposed facility are realistic for a facility of the size and design of a proposed project; and (3) whether costs are minimized consistent with the mitigation of environmental impacts. In fact, the Siting Council made the first two of these findings in the EEC Decision, but could not find that EEC had established that its cost estimates for the proposed facility had been minimized consistent with the mitigation of environmental impacts. 22 DOMSC at 297, 331. This latter finding was made in part in the EEC Compliance Decision and was further addressed in Sections II.B.5 and II.D, above. Further, in response to the Court directive regarding a comparison of alternatives, the Siting Board has found that the proposed project is superior to alternatives reviewed on the basis of cost.

C. Economic Development and Resource Use and Development Policies of the Commonwealth

In City of New Bedford, the Attorney General argued that the Siting Council had failed to perform a balancing to determine whether the environmental harm from the facility was outweighed by other statutory objectives because it elevated to primary importance economic development -- a factor not authorized by the statute.[382] 413 Mass. at 489. The Court stated:

> [t]he council acknowledges its extensive discussion about the economic benefit to the Commonwealth set forth in its analysis of need, but argues that its approval of the facility was in accord with the statutory requirements set forth in § 69H because the facility serves important policies and goals concerning resource use and development, consistent with the council's mandate to ensure an *adequate* supply at minimum cost. (footnote included in text below) In particular, it argues that the facility's contribution to reliability, cost, and stability satisfied the council that the project was consistent with goals of the statute.

Id. at 489-490.

The Court found that the Siting Council had misstated its mandate, and concluded that the statutory mandate requires the Siting Council to balance minimum environmental impact with lowest possible cost.[383] Id. at 490. Further, the Court noted that it is inappropriate to elevate to primary importance economic benefits to the Commonwealth over a balancing of these factors.[384] Id.

In its reviews of proposals to construct energy facilities, the Siting Council consistently first addressed the need for additional energy resources.[385] See Section II.C.1, above. The

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382 The Siting Board notes that the analysis of benefits to Massachusetts can be found at pages 50-74 of the EEC Decision, 22 DOMSC at 242-266. Of those twenty pages, only seven relate to economic benefits resulting from other than power sales from the proposed project. Id., 22 DOMSC at 244-250.

383 The Siting Board notes that such a balancing as it relates to the proposed EEC facility is contained in Section II.B.6, above.

384 The Court also stated that "[e]nsuring an adequate supply is not the same as 'provid[ing] a *necessary* energy supply for the commonwealth' (emphasis added). G.L. c. 164, § 69H." City of New Bedford, 413 Mass. at 490. This issue has been addressed in Section II.C.2.b, above.

385 As explained in n.56, above, the Siting Board altered its approach in this decision to first respond to the basis of the Court's remand of the EEC Decision, i.e., the comparison of alternatives.

economic benefits analysis, or more inclusively, the Massachusetts benefits analysis,[386] was included in a portion of the Siting Council's decision which lead to a finding of whether there was a need for additional energy resources, a finding that must precede any review or balancing of environmental impacts and costs.[387] The Siting Council undertook its review of Massachusetts benefits as a part of the need analysis, not because the issue of need is more important than the other statutory requirements, but rather because if need, including Massachusetts' need, for additional energy resources is not established, there is no reason to proceed to analyze the statutory requirements of minimum environmental impact and lowest possible cost.

In the NEA Decision, the Siting Council acknowledged that QF facility proposals of non-utility developers warranted some modifications to the standard of review established and used in prior utility facility cases.[388] 16 DOMSC at 349. Thus, where a non-utility developer was constructing a QF for one specific utility purchaser, the Siting Council noted that the applicant would have to demonstrate that utility needed the facility. Id. Where a non-utility developer has proposed a QF facility for a number of power purchasers that may include purchasers that are not yet known, or purchasers with retail territories outside of

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386 As noted by the Court, the analysis of economic benefits is set forth in the need analysis of the EEC Decision. City of New Bedford, 413 Mass. at 489-490.

387 The rationale for a review of Massachusetts benefits, i.e., reliability and economic benefits, was contained in the review of the first non-utility petition to construct a bulk generating facility which was filed with the Siting Council. See, NEA Decision, 16 DOMSC at 349. The Siting Council did not stray from this approach in the EEC Decision.

The Siting Council, after finding that EEC had established that additional energy resources in an amount at least equal to the output of the proposed project would be needed for the region for reliability purposes beginning in 1995 and beyond, then proceeded to review the potential for Massachusetts benefits consistent with its precedent. 22 DOMSC at 241, 242-266.

388 The Court acknowledged that such modifications may be necessary but noted that any such modifications "must permit a review that fulfills the statutory mandate." City of New Bedford, 413 Mass. at 488.

Massachusetts, the Siting Council noted that need could be established on a regional basis. Id. However, as the Siting Council's enabling statute required it to provide a necessary energy supply for the Commonwealth, the Siting Council required a non-utility developer that proposed to serve a regional need to "also demonstrate to the Siting Council that the proposed facility benefits Massachusetts." Id. Specifically, the non-utility developer was required to show that its proposed project "offers reliability or economic efficiency benefits to the Commonwealth in sufficient magnitude so that the construction of an energy facility in the state is consistent with the energy needs and resource use and development policies of the Commonwealth."[389] Id.

Had EEC been able to provide at the time of its petition or hearings thereon signed and approved PPAs with Massachusetts utilities for its complete output, the Siting Council would have had prima facie evidence, based on precedent, of the need for the proposed project to Massachusetts. However, as only a portion of the proposed project's output was subject to such PPAs, the Siting Council reviewed the benefits of the proposed project to Massachusetts.

As a result of this analysis, the Siting Council found that EEC's signed and approved PPAs supported a finding that the proposed project would offer reliability benefits to Massachusetts, the Siting Council further found that the proposed project would offer reliability benefits to Massachusetts as a result of the positive impacts to the electric transmission system in southeastern Massachusetts. Id., 22 DOMSC at 243-244, 261. The Siting Council also found that additional economic benefits would result from steam sales,

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389 The Siting Council noted that it was guided by G.L. c. 164, §69J which stated that the Siting Council shall approve a long-range forecast if it determines that it meets the requirements listed in that section. NEA Decision, 16 DOMSC at 345. Among those requirements is the requirement that: "plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth" (emphasis added). Id.

including overall reduced costs for fuel to steam purchasers.[390] In addition, the Siting Council found other economic benefits relating to the creation of jobs and tax revenues from the proposed project. Id., 22 DOMSC at 246, 248, 250. As noted in Section II.C.2, above, the Siting Board recognizes that over the course of the Siting Council's reviews, the definition of Massachusetts benefits which contribute to a showing of Massachusetts need was expanded to encompass other benefits which do not relate directly to the Massachusetts energy supply. The Siting Board recognizes that this was an inappropriate expansion of the standard of review and was inconsistent with our statutory mandate. Accordingly the Siting Board has corrected the standard in compliance with the Court's directive and our statutory mandate in this Decision.

The Siting Board acknowledges that its enabling statute contains no specific language requiring it to analyze economic benefits not directly tied to the energy supply that would accrue to the Commonwealth from a power generating facility proposed by a non-utility developer for construction in Massachusetts. Further, the Siting Board has not repeated any such analysis in its current review of EEC's petition. Nevertheless, the Siting Board notes that in order to treat utility and non-utility proposals in the same manner, an argument the Attorney General has urged in his discussion of the applicability of the IRM regulations in the Siting Board's review, all applicants should be required to establish that their plans for construction of new power generating facilities are consistent with the statutory requirement of G.L. c. 164, § 69J as it relates to the health, environmental protection, and resource use and development policies of the Commonwealth.

D. Other Issues

In City of New Bedford, the Court noted the Attorney General's argument that the Siting Council "failed explicitly to state that it was approving a dirtier fuel and plant on the basis that it had determined that other factors outweighed the acknowledged harm that would

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390 The Siting Board notes that reduced costs for fuel relates directly to the statutory mandate of providing an energy supply at the lowest possible cost. Further, as steam would be provided from a cogeneration facility, environmental impacts would likely be less than if separate sources of steam and electric generation were to be used.

be caused by the facility's construction and operation." 413 Mass. at 490. The Siting Board acknowledges that the Siting Council made no such explicit finding. Rather, the Siting Council concluded that, upon compliance with the conditions in the EEC Decision, "the construction of the proposed coal-fired generating facility and ancillary facilities is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." 22 DOMSC at 315.

The Siting Board can find no requirement in the statute, nor did the Attorney General cite the specific statutory language, that would permit the Siting Council to find that a proposed facility is the cleanest possible facility, or if it is not the cleanest possible facility, that other factors could outweigh the proposed facility's "acknowledged harm." See n.4 (in this section), above. The only possible language that would support such an argument appears to be the broad mandate that the energy resources that the Siting Board find to be necessary should provide such energy with a minimum impact on the environment at the lowest possible cost.

Thus, in order to find a statutory basis for the Attorney General's argument, the Siting Board must equate the term "acknowledged harm" with "minimum impact on the environment." Here, the Court has noted, the process is one of a balance among the statutory objectives. City of New Bedford, 413 Mass. at 485. A "dirtier fuel and plant," or a proposed facility with greater environmental impacts, therefore, can be approved if, on balance, the other objectives of the statute outweigh these greater environmental impacts. The Siting Board has addressed this balancing in Section II.B.7, above.

The Court also directed the Siting Council to provide a statement of reasons for each determination of fact or law necessary to its decision. Id. In response to this directive, the Siting Board has addressed each of the issues the Court identified that might arise on remand. The Siting Board has conducted an alternative's analysis of the type used by the Siting Council in its early reviews of non-utility petitions to construct power generating facilities and which was approved by the Court in City of New Bedford. Id., 413 Mass. at 485. The Siting Board has also analyzed the updated need information, including an analysis of Massachusetts need. Each issue of fact and law necessary to the decision has been highlighted in the "Findings and Conclusions" sections with reference to the specific area in the text where the supporting discussion and analysis can be found.

IV. DECISION

In City of New Bedford, the Court remanded the EEC Decision to the Siting Council for a comparison of the proposed project with other energy resource alternatives. 413 Mass. at 488. In addition, the Court noted other issues which may arise on remand.

Here, based on the record in this proceeding, the Siting Board has found, that the Company has established that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. Further, the Siting Board has found that, at such time that 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.

The Siting Board notes that all findings in the EEC Decision which were not remanded to the Siting Council, have not been revisited in this decision. Rather, the Siting Board recognizes that these findings remain in effect as per that decision. A summary of these findings can be found in Appendix A. In addition, the findings relative to the environmental compliance conditions which were addressed in the EEC Compliance Decision, remain in effect as per that decision. A summary of these findings can be found in Appendix B.

The Siting Board also notes that, in addition to the condition set forth in Section II.C.5, above, the approval of EEC's petition continues to remain 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 all conditions have been satisfactorily met. At that time the Siting Board will determine whether the proposed project will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Further, the Siting Board hereby requires EEC to comply with all conditions within four years of this Final Decision.

Robert P. Rasmussen
Hearing Officer

Dated this 27th day of October, 1993

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of October 22, 1993 by the members present and voting. Voting for approval of the Tentative Decision as amended: Kenneth Gordon (Chairman, ESFB/DPU); Barbara Kates-Garnick (Commissioner, DPU); Mary Clark Webster (Commissioner, DPU); Gloria C. Larson (Secretary of Economic Affairs); Trudy Coxe (Secretary of Environmental Affairs); Joseph Faherty (Public Member); William Sargent (Public Member).

Kenneth Gordon
Chairman

Dated this 25th day of October, 1993

TABLE 1

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2

lb/MMBtu

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10	CO_2[1]
CFB	10,200	0.15	0.23[2]	0.131	0.006	0.018	
NGCC	9,426	0.024	0.002	0.046	0.01	0.0035	
GOCC	9,246[3]	0.072	0.051	0.046	0.025	0.026	
CGCC[4]	10,830	0.066	0.136[5]	0.064	0.01	0.01	
PC	10,701	0.17	0.23	0.11	0.0036	0.018	
RO	10,858	0.15	0.29	0.033	0.005	0.04	
MCC[6]	8,250	0.009	0	0.01		0	

TPY

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10	CO_2
CFB	10,200	1,709	2,620	1,481	68	205	2,308,000
NGCC	9,426	254	21	485	106	37	1,287,000
GOCC	9,246	334	106	484	132	75	1,349,000
CGCC	10,830	726	1,649	774	121	121	2,359,000
PC	10,701	2,301	2,749	1,315	44	215	2,333,000
RO	10,858	1,819	3,517	400	61	485	2,091,000
MCC[7]	8,250		0			0	

Notes:

1 Emissions in lb/MMBtu were not provided for CO_2.
2 Based on use of 2.4% sulfur coal.
3 Heat rate based on oil firing. Heat rate for gas firing same as NGCC alternative.
4 Based on CGCC facility data provided by EEC. See Table Y for CGCC alternatives.
5 Based on use of 1.8% sulfur coal.
6 VOC emission factor was not provided.
7 Emission rates for NOx, CO and VOC were not provided. NO-COAL indicated that CO_2 emissions in lb/MMBtu would be 8.86% greater for an MCC facility than for a GOCC facility.

SOURCES: Exhs. AG-RE-18, att. 1, Table 6.3; AG-RE-38; SB-NC-36, at A-4, A-7, Workpaper 5, Workpaper 6.

TABLE 2

EMISSIONS OF CRITERIA POLLUTANTS AND CO_2
CFB/CGCC Alternatives

lb/MMBtu

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10
CFB	10,200	0.15	0.23[1]	0.13	0.006	0.018
CGCC (provided by EEC)	10,830	0.06	0.136[2]	0.064	0.011	0.01
CGCC (provided by EEC - based on A.G. heat rate)	9,872	0.06	0.136	0.064	0.01	0.01
CGCC (A.G. original)	9,872	0.12[3]	0.03[4]	0.09	0.0025	0.006
CGCC (A.G. update)[5]	8,814					
CGCC (Wabash permit)[6]	10,118	0.116	0.265	0.207	0.00263	0.00885

TPY

Technology	Heat rate	NOx	SO_2	CO	VOC	PM-10	CO_2
CFB	10,200	1,709	2,620	1,481	68	205	2,308,000
CGCC (provided by EEC)	10,830	726	1,629	774	121	1216	2,359,000
CGCC (provided by EEC - based on A.G. heat rate)	9,872	662	1,500	706	110	110	2,150,000
CGCC (A.G. original)	9,872	1,340	324	983	28	66	2,250,000
CGCC (A.G. update)	8,814						
CGCC (Wabash permit)[7]	10,118						

NOTES:

1 Based on use of 2.4% sulfur coal.
2 Based on use of 1.8% sulfur coal.
3 Emission factor without use of SCR - emission factor would be 0.048 with SCR.
4 Based on use of 1.8% sulfur coal.
5 No emissions data provided.
6 Wabash heat rate of 8,974 increased by 2% to reflect air-cooled condenser and by 965 Btu/kWh to reflect steam export.
7 Emissions in tpy was not provided.

SOURCES: Exhs. AG-RE-18, Table 6.3; AG-RE-38; AG-RR-45; AG-201, at 10-15; AG-205; JH-RR-1.

TABLE 3

PREDICTED CONTRIBUTIONS TO AMBIENT AIR QUALITY LEVELS
AS A PERCENT OF AMBIENT STANDARDS

Technology	NOx annual	NOx 3-hr	SO_2 24-hr	SO_2 annual	CO 1-hr	CO annual	PM-10 24-hr	PM-10 annual
CFB	0.2%	1.6%	1.6%	0.4%	0.07%	0.09%	0.3%	0.06%
NGCC	0.1%	0.04%	0.04%	0.01%	0.06%	0.08%	0.2%	0.03%
GOCC	0.1%	0.9%	0.8%	0.05%	0.06%	0.08%	1.0%	0.06%
CGCC[1]	0.3%	2.8%	2.7%	0.9%	0.1%	0.1%	0.5%	0.1%
PC	0.2%	1.4%	1.3%	0.4%	0.05%	0.06%	0.3%	0.05%
RO	0.2%	1.8%	1.7%	0.5%	0.02%	0.02%	0.6%	0.12%
NAAQS (micrograms per cubic meter)	100	1300	365	80	40,000	10,000	150	50

NOTES:

1 Based on CGCC facility data provided by EEC.

SOURCE: Exh. AG-RE-18, att. i, Table 6.4.

TABLE 4

LEVELIZED COSTS

Technology Parameters

	CFB	NGCC	NGCC	GOCC	GOCC	CGCC[1]	CGCC[2]	CGCC[3]	PC	RO
Heat rate[4]	10200	9426	7859	9396	7859	10832	10832	10832	10707	10858
Avail. factor (%)	85.0	90.5	90.5	90.5	90.5	85.5	85.8	85.8	84.0	74.3
Capital cost ($/kw)[5]	2176	870	870	888	888	2712	2712	2712	2246	1635

Levelized Costs
1997 $/MWh

	CFB	NGCC	NGCC	GOCC	GOCC	CGCC[1]	CGCC[2]	CGCC[3]	PC	RO
EEC coal	83.09					94.74	94.17	87.04[6]		
DOE		107.99	100.80[7]	92.18	86.00[8]	96.13	95.53	88.32	87.51	118.77
GTF		112.70	104.68	102.63	95.75	98.60			89.99	121.16
NEPEX		102.48	95.61	96.02	89.59	95.50			87.87	128.76
NGW		99.32	92.67	85.72	79.97					

NOTES:

1 Based on TAG data for a 200 MW, non-integrated facility.
2 Based on TAG data for a 200 MW, integrated facility.
3 Based on TAG data for a 400 MW, integrated facility.
4 All heat rates, except lower heat rates for NGCC and GOCC alternatives, are heat rates assumed by the Company. The lower heat rate for the NGCC is based on the heat rate for a recently proposed facility. The same lower heat rate was assumed for the GOCC alternative.
5 Capital costs do not reflect air cooled condensers for all technology alternatives or natural gas pipeline for the NGCC and GOCC alternatives. Under the GTF and NGW forecasts, capital costs were increased to reflect the air-cooled condenser for all technology alternatives and natural gas pipeline for the NGCC and GOCC alternatives.
6 Levelized cost estimate based on the percentage reduction in levelized cost for facility based on TAG data for a 200 MW non-integrated facility when EEC coal costs were substituted for 1.8 percent sulfur coal (DOE forecast).
7 Levelized cost computed by EEC. The same percentage reduction assumed in estimating the levelized costs for GTF, NEPEX and NGW forecasts.
8 Levelized costs estimated based on the percentage reduction in levelized costs for the lower heat rate for NGCC alternative.

SOURCES: Exhs.HO-AER-9(a)(A), Table 5.1, Table 5.3; HO-RR-116; HO-RR-128; HO-RR-110; HO-RR-124; HO-RR-123; HO-RR-121; AG-RR-61.

TABLE 5

RANGE OF REGIONAL NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1997

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	428	1,228	1,503	(561)	2,072
Ref	B	52	852	1,127	(937)	1,696
Ref	L	(326)	474	749	(1,315)	1,318
ExVal	H	(658)	142	417	(1,647)	986
ExVal	B	(1,034)	(234)	41	(2,023)	610
ExVal	L	(1,411)	(611)	(336)	(2,400)	233
GDP	H	(1,666)	(911)	(636)	(2,655)	(67)
GDP	B	(2,087)	(1,287)	(1,012)	(3,076)	(443)
GDP	L	(2,465)	(1,665)	(1,390)	(3,454)	(821)

1998

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	(371)	429	704	(1,557)	1,246
Ref	B	(792)	8	283	(1,978)	852
Ref	L	(1,214)	(414)	(139)	(2,400)	430
ExVal	H	(1,480)	(680)	(405)	(2,666)	164
ExVal	B	(1,901)	(1,101)	(826)	(3,087)	(257)
ExVal	L	(2,322)	(1,522)	(1,247)	(3,508)	(678)
GDP	H	(2,468)	(1,668)	(1,393)	(3,654)	(824)
GDP	B	(2,890)	(2,090)	(1,815)	(4,076)	(1,246)
GDP	L	(3,311)	(2,511)	(2,236)	(4,497)	(1,667)

TABLE 5 (page 2)

RANGE OF REGIONAL NEEDS CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1999

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(1,132)**	**(332)**	(7)	**(2,504)**	562
Ref	B	**(1,595)**	**(795)**	**(470)**	**(2,967)**	99
Ref	L	**(2,057)**	**(1,257)**	**(932)**	**(3,429)**	**(363)**
ExVal	H	**(2,205)**	**(1,405)**	**(1,080)**	**(3,577)**	**(511)**
ExVal	B	**(2,668)**	**(1,868)**	**(1,543)**	**(4,040)**	**(974)**
ExVal	L	**(3,130)**	**(2,330)**	**(2,005)**	**(4,502)**	**(1,436)**
GDP	H	**(3,158)**	**(2,358)**	**(2,033)**	**(4,530)**	**(1,464)**
GDP	B	**(3,621)**	**(2,821)**	**(2,496)**	**(4,993)**	**(1,927)**
GDP	L	**(4,082)**	**(3,282)**	**(2,957)**	**(5,454)**	**(2,388)**

2000

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(1,690)**	**(890)**	**(552)**	**(2,690)**	17
Ref	B	**(2,196)**	**(1,396)**	**(1,058)**	**(3,153)**	**(489)**
Ref	L	**(2,702)**	**(1,902)**	**(1,564)**	**(3,615)**	**(995)**
Ex	H	**(2,988)**	**(2,099)**	**(1,761)**	**(3,763)**	**(1,192)**
Ex	B	**(3,405)**	**(2,605)**	**(2,267)**	**(4,226)**	**(1,698)**
Ex	L	**(3,911)**	**(3,111)**	**(2,773)**	**(4,688)**	**(2,204)**
GDP	H	**(3,881)**	**(3,081)**	**(2,743)**	**(4,716)**	**(2,174)**
GDP	B	**(4,387)**	**(3,587)**	**(3,249)**	**(5,179)**	**(2,680)**
GDP	L	**(4,893)**	**(4,093)**	**(3,755)**	**(5,640)**	**(3,186)**

NOTES:

Low, base and high supply cases increased by 83 MW to account for committed portion of Enron facility. Highest contingency is "80% of "C" Planned Non-Utility Generation." Proportion of Enron deducted from highest contingency. Lowest contingency is "Existing Utility Attrition."

Bold signifies deficiency of at least 300 MW.

SOURCE: Exh. HO-RR-134

TABLE 6

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1997

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	584	1,384	1,725
Ref	B	407	1,207	1,548
Ref	L	(21)	779	1,120
ExVal	H	(497)	303	644
ExVal	B	(674)	126	467
ExVal	L	(1,102)	(302)	39
GDP	H	(1,546)	(746)	(405)
GDP	B	(1,723)	(923)	(582)
GDP	L	(2,152)	(1,352)	(1,011)

1998

Demand case	DSM	Low Supply	Base Supply	High Supply
Ref	H	(88)	712	1,053
Ref	B	(297)	503	844
Ref	L	(748)	52	393
ExVal	H	(1,187)	(387)	(46)
ExVal	B	(1,396)	(596)	(255)
ExVal	L	(1,847)	(1,047)	(706)
GDP	H	(2,168)	(1,368)	(1,027)
GDP	B	(2,377)	(1,577)	(1,236)
GDP	L	(2,828)	(2,028)	(1,687)

TABLE 6 (page 2)

RANGE OF REGIONAL NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-2000

1999

Demand case DSM		Low Supply	Base Supply	High Supply
Ref	H	**(668)**	132	523
Ref	B	**(954)**	(154)	237
Ref	L	**(1,433)**	**(633)**	(242)
ExVal	H	**(1,728)**	**(928)**	**(537)**
ExVal	B	**(2,014)**	**(1,214)**	**(823)**
ExVal	L	**(2,493)**	**(1,693)**	**(1,302)**
GDP	H	**(2,668)**	**(1,868)**	**(1,477)**
GDP	B	**(2,954)**	**(2,154)**	**(1,763)**
GDP	L	**(3,433)**	**(2,633)**	**(2,242)**

2000

Demand case DSM		Low Supply	Base Supply	High Supply
Ref	H	**(1,040)**	(240)	164
Ref	B	**(1,407)**	**(607)**	(203)
Ref	L	**(1,922)**	**(1,122)**	**(718)**
ExVal	H	**(2,228)**	**(1,428)**	**(1,024)**
ExVal	B	**(2,595)**	**(1,795)**	**(1,391)**
ExVal	L	**(3,110)**	**(2,310)**	**(1,906)**
GDP	H	**(3,194)**	**(2,394)**	**(1,990)**
GDP	B	**(3,562)**	**(2,762)**	**(2,358)**
GDP	L	**(4,076)**	**(3,276)**	**(2,872)**

NOTES: Table 6 incorporates the following changes from Table 5: (1) Reserve margins adjusted as follows: 22 percent in 1997, 21.5 percent in 1998, 21 percent in 1999 and 20.5 percent in 2000; (2) high DSM case is NEPOOL high DSM case; (3) low DSM case is NEPOOL low DSM case; (4) reference DSM case discounts DSM increment over 1991 by 8.4 percent; (5) high supply case includes uncommitted portion of MASSPOWER and Enron.

Bold signifies deficiency of at least 300 MW.

SOURCES: Exhs. HO-70, at 1; HO-RN 4(a) at 32; HO-RN-13(a)(u).

TABLE 7

RANGE OF MASSACHUSETTS NEED CASES (COMPANY ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-1998

1997

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(920)**	(288)	(20)	**(712)**	(85)
Ref	B	**(1,088)**	**(456)**	(188)	**(880)**	(254)
Ref	L	**(1,238)**	**(605)**	**(338)**	**(1,030)**	**(403)**
EndYr	H	**(1,272)**	**(640)**	**(372)**	**(1,064)**	**(438)**
EndYr	B	**(1,385)**	**(753)**	**(485)**	**(1,177)**	**(551)**
ExVal	H	**(1,418)**	**(786)**	**(518)**	**(1,210)**	**(584)**
EndYr	L	**(1,474)**	**(842)**	**(574)**	**(1,266)**	**(639)**
ExVal	B	**(1,587)**	**(955)**	**(687)**	**(752)**	**(1,379)**
Linear Regr		**(1,603)**	**(971)**	**(703)**	**(1,395)**	**(769)**
ExVal	L	**(1,736)**	**(1,104)**	**(836)**	**(902)**	**(1,529)**
CAGR Regr		**(2,136)**	**(1,504)**	**(1,236)**	**(1,302)**	**(1,928)**

1998

Demand case	DSM	Low Supply	Base Supply	High Supply	Lowest Cont.	Highest Cont.
Ref	H	**(1,231)**	**(598)**	**(331)**	**(1,110)**	**(397)**
Ref	B	**(1,424)**	**(792)**	**(524)**	**(1,303)**	**(590)**
EndYr	H	**(1,533)**	**(901)**	**(633)**	**(1,412)**	**(699)**
Ref	L	**(1,593)**	**(961)**	**(693)**	**(1,472)**	**(759)**
EndYr	B	**(1,672)**	**(1,040)**	**(772)**	**(1,551)**	**(838)**
ExVal	H	**(1,740)**	**(1,108)**	**(840)**	**(1,629)**	**(906)**
EndYr	L	**(1,781)**	**(1,149)**	**(881)**	**(1,660)**	**(947)**
Linear Regr		**(1,815)**	**(1,183)**	**(915)**	**(1,694)**	**(981)**
ExVal	B	**(1,933)**	**(1,301)**	**(1,033)**	**(1,812)**	**(1,099)**
ExVal	L	**(2,103)**	**(1,471)**	**(1,203)**	**(1,982)**	**(1,269)**
CAGR regr		**(2,441)**	**(1,808)**	**(1,540)**	**(2,329)**	**(1,606)**

Bold signifies deficiency of at least 300 MW.

SOURCE: HO-MN-39, att. 7-12 to 7-23

TABLE 8

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-1998

1997

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(848)	(216)	82
Ref B	(920)	(288)	108
Ref L	(1,142)	(510)	(212)
EndYr H	(1,173)	(541)	(243)
EndYr B	(1,244)	(612)	(314)
ExVal H	(1,345)	(713)	(415)
EndYr L	(1,350)	(718)	(420)
ExVal B	(1,417)	(785)	(487)
Lin Regr	(1,553)	(921)	(623)
ExVal L	(1,639)	(1,007)	(709)
CGR Regr	(2,083)	(1,451)	(1,153)

1998

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	(1,099)	(467)	(169)
Ref B	(1,185)	(553)	(255)
EndYr H	(1,371)	(739)	(441)
Ref L	(1,416)	(784)	(486)
EndYr B	(1,457)	(825)	(527)
EndYr L	(1,587)	(955)	(657)
ExVal H	(1,605)	(973)	(675)
ExVal B	(1,691)	(1,059)	(761)
Lin Regr	(1,711)	(1,079)	(781)
ExVal L	(1,922)	(1,290)	(992)
CGR Regr	(2,331)	(1,699)	(1,401)

TABLE 8 (page 2)

RANGE OF MASSACHUSETTS NEED CASES (STAFF ANALYSIS)
SURPLUS/(DEFICIENCY)
1997-1998

1999

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	**(1,368)**	**(736)**	**(390)**
Ref B	**(1,489)**	**(857)**	**(511)**
EndYr H	**(1,580)**	**(948)**	**(602)**
EndYr B	**(1,682)**	**(1,050)**	**(704)**
Ref L	**(1,731)**	**(1,099)**	**(753)**
EndYr L	**(1,837)**	**(1,205)**	**(859)**
ExVal H	**(1,855)**	**(1,223)**	**(877)**
Lin Regr	**(1,877)**	**(1,245)**	**(899)**
ExVal B	**(1,976)**	**(1,344)**	**(998)**
ExVal L	**(2,218)**	**(1,586)**	**(1,240)**
CGR Regr	**(2,591)**	**(1,959)**	**(1,613)**

2000

Demand case DSM	Low Supply	Base Supply	High Supply
Ref H	**(1,544)**	**(912)**	**(566)**
Ref B	**(1,709)**	**(1,067)**	**(721)**
EndYr H	**(1,770)**	**(1,138)**	**(792)**
EndYr B	**(1,889)**	**(1,257)**	**(911)**
Ref L	**(1,954)**	**(1,322)**	**(976)**
Lin Regr	**(2,018)**	**(1,386)**	**(1,040)**
EndYr L	**(2,070)**	**(1,438)**	**(1,092)**
ExVal H	**(2,092)**	**(1,460)**	**(1,114)**
ExVal B	**(2,247)**	**(1,615)**	**(1,269)**
ExVal L	**(2,502)**	**(1,870)**	**(1,524)**
CGR Regr	**(2,835)**	**(2,203)**	**(1,857)**

NOTES: Table 8 incorporates changes from Table 7 comparable to those incorporated in Table 6 from Table 5. **Bold** signifies deficiency of at least 300 MW.

SOURCES: Exhs. HO-MN-39, att. 7-4, 7-5, 7-9; HO-JH-RR-11R; HO-70 at 1; HO-RN 4(a) at 32

APPENDIX A -- EEC DECISION

The Siting Council staff commenced its review of EEC's petition to construct its 300 MW CFB cogeneration power plant by issuing a public hearing notice and holding a public hearing in the City of New bedford. Motions to Intervene were filed by the Attorney General, the Department of Environmental Management ("DEM"), the CNB, Codman & Shurtleff, Inc.,[391] and the NO-COAL. Petitions to participate as an interested person were filed by Robert H. Ladino, Henry B. Riley, and Mary T. and Donald J. Marshall. On May 17, 1990, the Hearing Officer conducted a pre-hearing conference at which all petitions to intervene and all petitions to participate as an interested person were allowed and discovery and hearing schedules were established.

The Siting Council conducted 14 days of evidentiary hearings commencing October 9, 1990 and ending November 7, 1990. EEC presented 13 witnesses: Robert M. Earsy, a noise consultant, who testified regarding noise impacts of the facility; Steven P. Damiano, an environmental scientist employed by ENSR, who testified regarding impacts to wetlands, wildlife and the Acushnet Cedar Swamp State Reservation;[392] James H. Slack, a senior program manager for ENSR, who testified regarding air permits and air resource impacts; Denis King, project engineer for Bechtel Power Corporation ("BPC"), who testified regarding project design and technical activities of the project; Ronald C. Denhardt, a senior economist with Jensen Associates, Inc., who testified regarding natural gas issues relating to the proposed facility; Glen Harkness, vice president of ENSR, who testified regarding the environmental studies and permit applications that were prepared by ENSR; Theodore F. Kuhn, an executive economist with R. W. Beck and Associates ("R. W. Beck"), who testified regarding demand forecasts; James L. Croyle, general manager for the project, who testified regarding steam sales, PPAs, project construction, financing, operation, and site selection; Gary W. Warner, partner and manager of the Boston Engineering Office of R. W.

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391 The intervention of Codman & Shurtleff, Inc. was withdrawn on July 16, 1990.

392 The Acushnet Cedar Swamp State Reservation abuts the parcel on which the proposed facility would be constructed.

Beck, who testified regarding local electric system reliability and transmission issues; John P. Smith, an independent consultant in the coal industry, who testified regarding coal procurement issues; William R. Lane, an engineering specialist for BPC, who testified regarding pollution control issues; and Roger M. Cotte, a partner and manager of R. W. Beck, and James A. Booth, principal engineer of the Boston Consulting Office of R. W. Beck, both of whom testified regarding power supply and need assessment.

The Attorney General presented two witnesses: Dr. Barbara D. Beck, a principal with the Gradient Corporation, an environmental consulting firm, who testified regarding health risk assessments, and Dr. C. Michael Mohr, of Energy and Environmental Engineering, Inc. and the Massachusetts Institute of Technology, who testified regarding fluidized bed coal combustors.

DEM presented one witness, Andrew E. Backman, a natural resource planner, who testified regarding environmental impacts to wetlands and the Acushnet Cedar Swamp State Reservation.

In addition, pre-filed testimony was introduced for CNB by Mark J. Mello, the acting director of the Lloyd Center for Environmental Studies, regarding wetland delineation for the project area, and for NO-COAL, by Stephen B. Cook, a NO-COAL member, regarding the location of power generating facilities in Southeastern Massachusetts.[393]

On December 11 and 12, 1990, initial briefs were filed by EEC, the Attorney General, DEM, CNB, NO-COAL, and Robert H. Ladino. Reply briefs were filed on December 21, 1990 by EEC, the Attorney General and by NO-COAL and Robert H. Ladino jointly.

On April 24, 1991, in response to the release of the 1991 CELT Report, the Hearing Officers reopened the record for the limited purpose of receiving additional information relative to that document. Because EEC had addressed the 1989 and 1990 CELT Reports in this case, the Hearing Officers required EEC to update its application and afforded EEC, as

393 Although pre-filed testimony was submitted by both Mark J. Mello and Stephen B. Cook and introduced into the record, neither witness testified at the hearings.

well as the intervenors and interested persons, an opportunity to submit additional information and a supplemental brief. Supplemental Briefs were filed on May 7 and 9, 1991 by EEC, the Attorney General, NO-COAL, and Robert H. Ladino. Supplemental Reply Briefs were filed on May 14, 1991 by EEC and by NO-COAL.

The Hearing Officers entered 413 exhibits into the record, consisting largely of responses to information and record requests. EEC entered 57 exhibits into the record. The Attorney General entered 181 exhibits into the record. DEM entered 7 exhibits into the record. CNB entered 3 exhibits into the record. NO-COAL entered 10 exhibits into the record.

The following is a list of the major findings, conditions and orders which were made by the Siting Council in the EEC Decision.

> EEC has established that (1) New England needs at least 300 MW of additional energy resources for reliability purposes beginning in 1995 and beyond, and (2) the proposed project would provide benefits to the Commonwealth of sufficient magnitude to offset the impacts on the Commonwealth's resources from construction and operation of the proposed project. EEC Decision, 22 DOMSC at 267.
>
> EEC has established that the proposed project approach is consistent with the broad resource use and development policies of the Commonwealth. Id. at 295.
>
> EEC has demonstrated that its proposed project (1) is reasonably likely to be financed and constructed so that the project will actually go into service as planned if it enters into an appropriate EPC contract, and (2) is likely to operate and be a reliable, least-cost source of energy over the life of its power sales agreements if (a) EEC executes an appropriate O&M agreement which includes financial incentives and/or penalties which ensure reliable performance over the life of the unit, and (b) EEC executes a coal supply agreement which includes terms similar to those found in the RFP. Id. at 312.
>
> (1) EEC has developed an acceptable set of criteria for identifying and evaluating [other site] alternatives; (2) EEC has appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensures that it has not overlooked or eliminated any clearly superior sites; and (3) EEC is not required to provide an alternative site with

some measure of geographic diversity . . . [and, therefore] that EEC has considered a reasonable range of practical facility siting alternatives. Id. at 326.

EEC has established that the cost estimates associated with the proposed facilities are realistic for a facility of the size and design of the proposed project. Id. at 331.[394]

With regard to air quality, the Siting Council has found that the Company's methodology for estimating air pollutant emission rates is acceptable. In regard to the impact of air emissions from the proposed facility on air quality, the Siting Council has found that pollutants from the proposed plant other that VOCs, NOx, SO_2 and CO_2 would not add significantly to the existing air pollutant concentrations and are adequately minimized.

The Siting Council has ORDERED EEC to minimize the VOCs emitted from the proposed facility consistent with expected emission levels of 0.005 lb/MMBtu to 0.007 lb/MMBtu, and to provide the Siting Council with documentation of the VOC emission rate guaranteed by the vendor ultimately selected by EEC. Based on the Company's compliance with the above ORDER, the Siting Council has found that emissions of VOCs will be adequately minimized.

The Siting Council has also ORDERED the Company to utilize ammonia or urea injection in order to reduce NOx emissions after three years of facility operation, if combustion optimization does not achieve the expected reduction of NOx emissions from 0.30 lb/MMBtu to 0.18 lb/MMBtu or lower. Based on the Company's compliance with the above ORDER, the Siting Council has found that NOx emissions will be adequately minimized.

With regard to SO_2, the Siting Council has found that if (a) the Company provides a comprehensive analysis of the availability, environmental impact and economic impact of lower sulfur coal, and (b) the Siting Council determines, after review, that the use of 1.8 percent sulfur coal or a lower sulfur coal achieves the appropriate balance based on our standard, then the proposed facility's SO_2 emissions will be adequately minimized.

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394 Because a final determination on cost could not be made until all costs of environmental mitigation were made known to the Siting Council, the Siting Council made no finding as to whether EEC has established that the cost estimates of the proposed facility have been minimized consistent with the mitigation of environmental impacts (Id. at 331). The Siting Council withheld its determination until EEC filed its information relative to environmental issues.

With regard to CO_2, the Siting Council has found that if (a) the Company provides its plan for attaining CO_2 emission offsets through participation in the Massachusetts Releaf Program or other methods, and a comprehensive analysis of the economic and environmental impacts of attaining a range of CO_2 emission offsets, and (b) the Siting Council determines, after review, that the Company's plan for attaining CO_2 emission offsets or a different CO_2 emission offset plan achieves the appropriate balance based on our standard, then CO emissions will be adequately minimized.

Finally, with respect to air quality, the Siting Council has found that the operation of the proposed facility will have an acceptable impact on vegetation and soils, and that a health risk assessment is not required for the proposed facility.

With regard to noise, the Siting Council has found that if (a) the Company provides a revised analysis of the noise impacts of the proposed facility at the closest residence, and a description of the various strategies the Company would use to further minimize noise impacts of the proposed facility at the northern property line, and (b) the Siting Council determines, after review, that the Company's plan for reducing noise impacts or a different plan for reducing noise impacts is consistent with the minimization of noise impacts, then noise impacts will be adequately minimized.

With regard to water resources, the Siting Council has ORDERED the Company to replicate wetlands on-site, in an amount greater than the amount of wetlands that will be altered. Based on the Company's compliance with the above ORDER, the Siting Council has found that the alteration of on-site wetlands that will result from construction of the proposed facility will be acceptable. The Siting Council has also ORDERED the Company to (1) develop a comprehensive stormwater monitoring plan, in consultation with DEM and the [New Bedford Conservation Commission], and (2) submit this monitoring plan to the Siting Council. The Siting Council has further ORDERED the Company to maintain at least 30 feet of existing vegetation, during construction and operation of the proposed facility, between the on-site wetlands and (1) the coal storage enclosure, and (2) the rail spur extending to the south of the coal storage enclosure. Based on the Company's compliance with the above ORDERS, the Siting Council has found that the construction and operation of the proposed facility will have an acceptable impact on the on-site wetlands and the Acushnet Swamp. In addition, the Siting Council has found that the proposed facility will have: (1) acceptable visual impacts; (2) an acceptable impact with respect to water supply; and (3) an acceptable impact with respect to wastewater discharge.

With regard to existing land uses, the Siting Council has ORDERED the Company to (1) maintain at least ten feet of existing vegetation, during construction and operation of the proposed facility on the western boundary of the proposed site, in the vicinity of the parking area, oil storage tank and limestone storage building, where the tree clearing line is proposed to extend along the Acushnet Cedar Swamp State Reservation boundary, and (2) maintain at least 100 feet of existing vegetation, during construction and operation of the proposed facility along all other portions of the western boundary and along the southern boundary of the proposed site. Based on the Company's compliance with the above ORDER, the Siting Council has found that the proposed facility would have an acceptable impact on existing land uses.

With regard to solid waste, the Siting Council has ORDERED the Company to submit either (1) a signed agreement for the removal of ash, which includes provisions to ensure safe and environmentally acceptable removal thereof, or (2) the signed coal supply contract, which includes specific provisions to ensure safe and environmentally acceptable removal of the ash. Based on the Company's compliance with the above ORDER and the completion of arrangements with MDEP-licensed entities to dispose of sludge and oily wastes, the Siting Council has found that the solid waste impacts of the proposed facility would be acceptable.

Finally, the Siting Council has found that (1) increased vehicular and rail traffic due to the operation of the proposed facility will have an acceptable impact on the traffic flow in the vicinity of the proposed facility, and (2) the proposed facility will incorporate adequate safety measures. Id. at 310-313.

APPENDIX B -- EEC COMPLIANCE DECISION

The Siting Council staff commenced its review of EEC's Compliance Filing by issuing a discovery schedule and tentatively scheduling hearings for April of that year.[395] Following a five-week discovery period, five days of evidentiary hearings were held. EEC presented five witnesses who had testified in the initial proceedings: James H. Slack, who testified regarding air permits and air emissions; Robert M. Earsy, who testified regarding noise impacts of the proposed facility; Glen Harkness, vice president of ENSR, who also testified regarding noise impacts of the proposed facility; James L. Croyle, who testified regarding CO_2 mitigation, SO_2 offsets, project viability, and project costs; and James A. Booth, who testified regarding dispatch of the proposed facility. EEC presented two additional witnesses: Arshad Nawaz, project engineer for BPC, who testified regarding project design and technical aspects of the project; and Ben G. Henneke, Jr., president of Envirofuels Corporation, who testified regarding sulfur content, availability, and costs of different coals. No additional witnesses were sponsored by the Attorney General or NO-COAL.

The Hearing Officer entered 115 exhibits into the record, consisting of the Compliance Filing and responses to information and record requests. The Attorney General and EEC entered 59 exhibits into the record. NO-COAL entered 27 exhibits into the record.[396]

Briefs were filed on May 21, 1992 by EEC, the Attorney General and NO-COAL. By agreement of the parties, reply briefs were not filed.

The following is a list of the findings which were made by the Siting Council in the EEC Compliance Decision.

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[395] Although all parties and interested persons were notified of the new proceeding and of their continued rights in the new proceeding, only the Attorney General and NO-COAL continued to actively intervene.

[396] These exhibits were in addition to the exhibits entered into the record in the review of EEC's original petition (EFSC 90-100). The exhibits in that proceeding were included in the record in the review of the Compliance Filing.

EEC has complied with the condition to provide (1) a revised analysis of the noise impacts of the proposed facility at the closest residence, and (2) a description of the various strategies the Company would use to further minimize noise impacts of the facility at the northern property line. The Siting Council has also found that EEC has established that the noise levels of the proposed facility with the revised mitigation strategy described above have been adequately minimized consistent with the minimization of cost. EEC Compliance Decision, 25 DOMSC at 318.

[With respect to SO_2, t]he Company complied with the condition in [the] EEC [Decision] to provide a comprehensive analysis of the availability, environmental impact and economic impact of the use [of] coal with a range of sulfur contents below 1.8 percent at the proposed facility. The Siting Council also has found that the use of lower sulfur coal may be consistent with the adequate minimization of SO_2 emissions from the proposed facility, consistent with the minimization of cost.

In addition, the Siting Council has found that a ten percent decrease in the SO_2 emission rate to 0.225 lb/MMBtu would be consistent with an adequate minimization of the SO_2 emissions from the proposed facility, consistent with minimizing cost.

Finally, the Siting Council has found that an SO_2 emissions offset program that would result in a decrease in SO_2 emissions from electric generating facilities in Massachusetts of at least 660 tons per year, with at least 330 tons per year from electric generating facilities in southeastern Massachusetts, would be consistent with an adequate minimization of the SO_2 emissions from the proposed facility, consistent with minimization of cost, provided that the program: (1) costs no more than the costs of achieving an emission rate at the proposed facility of 0.225 lb/MMBtu with use of 1.8 percent sulfur coal; (2) is acceptable to the Department of Environmental Protection or other appropriate state agency(s); (3) would result in verifiable, quantifiable SO_2 emissions offsets for the operating life of the proposed facility; (4) would not require increases in emission levels for any regulated pollutants at the proposed facility over any permit levels determined in conjunction with an emission rate of 0.25 lb/MMBtu based on the use of 1.8 percent sulfur coal; and (5) would result in incremental emission reduction benefits.

In sum, the Company's original proposal to utilize 1.8 percent sulfur coal to achieve an SO_2 emission rate of 0.25 lb/MMBtu does not represent adequate minimization of SO_2 emissions. However, there are a number of options that EEC may undertake that would adequately minimize SO_2 emissions, consistent with the minimization of cost. The Company can reduce SO_2 emissions from the proposed facility from 0.25 lb/MMBtu to

0.225 lb/MMBtu or less by use of coal with a sulfur content below 1.8 percent, by optimization of the design and operation of the CFB boiler, or by a combination of both methods. In the alternative, the Company can minimize the SO_2 emissions from the proposed facility by arranging to reduce at least 660 tpy of SO_2 emissions from other generating facilities in Massachusetts, or a reduction consistent with the discussion above if the DEP determines BACT for the proposed facility to be less than 0.25 lb/MMBtu. The Siting Council recognizes that the Company can best determine which option would be most cost-effective in minimizing the SO_2 emissions from the proposed facility. Therefore, the Siting Council will allow the Company to decide which option to pursue.

Accordingly, based on the foregoing, the Siting Council finds that if EEC adopts one or more of the above discussed methods for mitigating SO_2 emissions, the SO_2 emissions from the proposed facility would be adequately minimized, consistent with [the] minimization of cost. Id. at 346-348.

[T]he Company has adequately complied with the condition to provide its plan for attaining CO_2 mitigation offsets through participation in MASS ReLeaf or other methods and a comprehensive analysis of the environmental and economic impacts of attaining a range of CO_2 emission offsets.

In addition, the Siting Council has found that a CO_2 mitigation plan that commits EEC to contribute a total of $2 million in present value terms, including as significant shares (1) a contribution to MASS ReLeaf, and (2) a contribution through a credible organization or group of organizations to a reforestation program, local, national, or international, would be consistent with an adequate minimization of CO_2 emission impacts from the proposed facility, consistent with the minimization of cost, provided that the above contributions are fully paid within five years of start up of the proposed facility. Id. at 367-368.

With respect to noise impacts, . . . EEC's proposed noise mitigation strategy, with an incremental cost of $230,000, would minimize noise impacts, consistent with minimizing cost. Id. at 372.

With respect to SO_2, the record indicates that SO_2 emissions can be minimized, consistent with the minimization of cost, in several ways . . . [and] that through the use of one or more of these methods, SO_2 emissions form the facility would be minimized consistent with the minimization of costs. Id. at 371-372.

[W]ith respect to CO_2, the record indicates that CO_2 emissions also can be minimized, consistent with the minimization of cost, in several ways . . . [and that] contributions to the extent of a minimum of $2 million over the first five years of the proposed facility's operation would minimize the impacts of CO_2 emissions consistent with the minimization of costs. Id. at 372.

[In conclusion, t]he Siting Council has found that the construction and operation of the proposed facility at the proposed site, subject to the directives contained herein and based on compliance with the orders in [the] EEC [Decision], will have acceptable environmental impacts.

The Siting Council has also found that the cost estimates associated with the proposed facility are minimized consistent with the mitigation of environmental impacts.

Accordingly, the Siting Council finds that the construction and operation of the proposed facilities at the proposed site is acceptable in terms of cost and in terms of environmental impacts, subject to the directives contained herein, and based on compliance with the orders contained in [the] EEC [Decision]. Id.

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).