Decisions and Orders

Massachusetts Energy Facilities Siting Board

VOLUME 7

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

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ORDER ON RULEMAKING

M. Kathryn Sedor
Hearing Officer
July 17, 1998

On the Decision:
Jeffrey Brandt

I. INTRODUCTION

A. Background

The recently enacted Electric Restructuring Act requires the Energy Facilities Board ("Siting Board") "periodically" to "conduct a rulemaking to establish a technology performance standard ("TPS") for generating facilities emissions . . ." G.L. c. 164, § 69J¼, added by St. 1997, c. 164, § 210. The Electric Restructuring Act contemplates that the TPS will be used to determine the scope of the Siting Board's review of electric generating facility petitions filed for review pursuant to G.L. c. 164, § 69J¼.

Pursuant to G.L. c. 164 § 69J¼, if a petition for approval of an electric generating facility indicates that the expected air emissions from the proposed facility will exceed the levels set in the TPS, the facility proponent must provide the Siting Board with information regarding the cost, reliability and environmental impacts of other fossil fuel generating technologies. The Siting Board then must determine whether "the construction of the proposed facility on balance contributes to a reliable, low-cost, diverse, regional energy supply with minimal environmental impacts." G.L. c. 164, § 69J¼. Conversely, if expected facility emissions meet or are below the levels set forth in the TPS, the facility proponent need not conduct an analysis of alternative generation technologies.

B. Procedural History

In response to the statutory mandate set forth in G.L. c. 164, § 69J¼, the Siting Board, with input from the Massachusetts Department of Environmental Protection ("MDEP"), began to develop a Technology Performance Standard early in 1998. On April 21, 1998, the Siting Board by unanimous written consent approved promulgation of the Technology Performance Standard at 980 CMR 12.00, as an Emergency Regulation ("Emergency Rule"). As expressly required by G.L. c. 164, § 69J¼, the Emergency Rule set forth pollutant-specific emissions limits for air pollutants. As further provided by § 69J¼, the emissions limits in the Emergency Rule represented the emissions of electric generating facilities with "state of the art environmental performance characteristics," while also incorporating the additional mandate in § 69J¼ that the TPS promote the control and reduction of facility-related water withdrawals. See G.L. c. 164, §69 J¼, second paragraph. These limits were based in large part on air permits issued by MDEP for the three electric generating facilities most recently approved by the Siting Board.

On May 15, 1998, as required by G.L. c. 30A, the Siting Board issued a Notice of Proposed Rulemaking and Notice of Public Hearing with respect to promulgation of the Emergency Rule as a final regulation.[1] The public hearing was conducted on June 9, 1998.

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1 In addition to G.L. c. 30A, promulgation of Siting Board regulations is governed by 950 C.M.R 20.00, the regulations implementing G.L. c. 30A, and by the Siting Board's "Rules for Adopting Administrative Regulations" at 980 C.M.R 2.00. Both

A total of eight persons provided comments on the Emergency Rule.[2] The commenters were: the Sierra Club Massachusetts Chapter ("Sierra Club"), Sithe Energies, Inc. ("Sithe"), US Generating Company ("USGen"), Clean Water Action ("CWA"), Smith & Croyle, LLC ("S&C"), the Conservation Law Foundation ("CLF"), the Massachusetts Public Interest Research Group ("MASSPIRG"), and the Competitive Power Coalition ("CPC").

Based on its review of the public comments received, the Siting Board has modified the Emergency Rule in certain respects. On July 9, 1998, the Siting Board met to determine whether the Emergency Rule, as modified, should be submitted to the Secretary of State for publication as a final regulation.[3]

C. Methodology

The Siting Board developed emission standards for criteria pollutants using baseline data from Prevention of Significant Deterioration ("PSD") permits recently issued by the MDEP for three Massachusetts power plants: the Berkshire Power Development project in Agawam, U.S. Generating Company's Millennium project in Charlton, and the Dighton Power Associates project in Dighton. These power plants use natural gas-fired combined cycle technology, and range in size from 170 to 360 MW.

The emissions levels in the PSD permits represent Best Available Control Technology ("BACT") for SO_2, CO, and PM_{10}, and the Lowest Achievable Emission Rate ("LAER") for NO_x and VOCs.[4] Thus, by using the PSD permits as baseline data, the Siting Board complies with the requirements in G.L. c. 164 § 69J¼ that the TPS reflect (1) BACT or

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sets of regulations are based on and conform with the statutory requirements of G.L. c. 30A. See, G.L. c. 30A, §§ 2-6A.

2 Four persons provided oral comments on the record at the public hearing, and seven sets of comments were filed during the subsequent ten-day public comment period.

3 Because it was initially promulgated as an Emergency Rule, the TPS, if approved by the Siting Board, must be filed with the Secretary of State no later than August 7, 1998, or the Secretary of State will file a Notice of Expiration. If timely filed, the TPS will become effective upon publication in the State Register on August 21, 1998. See 950 C.M.R. 20.05.

4 LAER, a more stringent standard than BACT, requires the use of the pollution control technology with the lowest achievable emission rate *irrespective* of cost effectiveness. BACT, on the other hand, factors cost effectiveness considerations into the emission standard. Massachusetts is a non-attainment area for ozone; therefore, in order to comply with the National Ambient Air Quality Standards, MDEP requires developers to meet LAER for NO_x and VOCs, which are precursors to ozone formation.

LAER, whichever is applicable, and (2) achievable emissions rates as demonstrated by MDEP air permits.

Emission levels in the PSD permits were specified in units of pounds per hour. In order to compare the emissions of facilities with different generating capacities, the Siting Board converted these emissions levels to pounds per megawatt-hour, by dividing the pounds per hour value by the generating capacity of the facility in megawatts. These converted values appear in Table 1, below. The Siting Board determined the TPS level for each pollutant by taking the highest of the three permitted levels and adding a ten percent "safety factor". This safety factor is intended to reflect "the best available and most efficient technology to control and reduce water withdrawals" (G.L. c. 164, § 69J¼) by allowing for minor reductions in plant efficiency due to aggressive measures to control water consumption; it also allows for the potential effects of minor variations in plant configuration or turbine design. The TPS values are shown in the right hand column of the Table 1.

Table 1
Comparison of Plant Emissions and Proposed Technology Performance Standards
Criteria Pollutants

Pollutant	**Berkshire Emission Limits(1)** lbs per MW-hr	**Millennium Emission Limits(2)** lbs per MW-hr	**Dighton Emission Limits(3)** lbs per MW-hr	**Highest MDEP Emission Factors of the Three Most Recently Permitted Power Plants** lbs per MW-hr	**Technology Performance Standards with 10% Safety Factor** lbs per MW-hr
NO_x	0.077	0.090	**0.110**	0.110	0.120
CO	0.054	**0.070**	0.038	0.070	0.077
VOCs	0.024	0.009	**0.032**	0.032	0.035
SO_2	0.015	0.016	**0.019**	0.019	0.021
PM and PM-10	0.064	0.035	**0.074**	0.074	0.081

Table Notes:

(1) Berkshire Emission Limits are based on MDEP Prevention of Significant Deterioration Air Permit dated 9/22/97, Appendix A-1. Emission limits are based on stack emission limits which are the sum of

turbine emission limits plus chiller engine emission limits. Rates are based on burning natural gas at 100% load at 59 degree F ambient temperature.

(2) Millennium Emission Limits are based on MDEP Prevention of Significant Deterioration Air Permit dated 11/26/97. Emission limits are based on burning natural gas at 100% load and 60 degree F. CO and VOCs values are from Attachment B and SO_2, PM_{10}, and NO_x are from Attachment C of the referenced permit.

(3) Dighton Emission Limits are based on MDEP Prevention of Significant Deterioration Air Permit dated 8/28/97. Values are from Table II. Ambient temperatures for emissions were 50 degrees F.

As reflected in Table 1, the Dighton facility had the highest permitted level of emissions for all pollutants except CO. Accordingly, the Emergency Rule incorporated these levels, and specified a test temperature of 50 degrees Fahrenheit, the temperature at which the Dighton facility was tested. The highest permitted value for CO came from the U.S. Generating facility, which was tested at 60 degrees F. To ensure consistent testing conditions across all five criteria pollutants, it was necessary to select a single ambient air temperature at which emissions levels will be reported. We selected 50 degrees F, the temperature used for the Dighton facility. Lowering the test temperature ten degrees from the 60 degrees F used in the USGen permit would not affect USGen's reported CO emissions, and doing so allows for use of the 50 degree F testing temperature for all five of the criteria pollutants.

The Siting Board also sought to use recently issued PSD permits to establish TPS emissions levels for non-criteria pollutants. However, only the Berkshire Power Development permit addressed heavy metals, and the levels in that permit applied only to periods when the project was burning oil as a backup fuel (Appendix D of the Berkshire PSD Permit). As the intent of the TPS is to address emissions from the primary fuel source, the Siting Board applied the non-criteria pollutant limits in the Berkshire permit to the primary fuel.

As in the case of the criteria pollutants, the Siting Board converted the permitted values from pounds per hour to pounds per megawatt-hour to allow the application of the TPS emission levels to facilities of all sizes. The TPS test temperature for heavy metals is 0 degrees Fahrenheit, the temperature specified by the U.S. Environmental Protection Agency ("EPA") for determining the pollution emissions in the Berkshire permit. (The information in the PSD permit was derived by MDEP using EPA AP-42 Emission Factors, 1/95 Table 3.1-7, "Trace Element Emission Factors for Distillate Oil Fired Gas Turbines").

II. COMMENTS AND ANALYSIS

A. Proposed Changes to Technical Performance Standards

1. Summary of Comments

The Siting Board received comments recommending that standards for carbon dioxide (CO_2) be added to the set of criteria pollutants covered by the Emergency Rule; due to its environmental and health impacts (MASSPIRG Comments at 5; CWA Comments at 1; Sierra Club Comments at 2). A comment also was received recommending that lead be included in the TPS (Sierra Club Comments at 2).

Certain commenters recommended that the Siting Board adopt specific performance standards for water use (MASSPIRG Comments at 4; CWA Comments at 1; Sierra Club Comments at 1). Comment letters acknowledged that the Siting Board's proposed standards incorporate a safety factor to allow for facilities that have slightly higher emissions because of equipment associated with water conservation (id.). However, the comments stated that the Siting Board should include specific water use standards that reflect the use of state of the art cooling technologies which minimize the amount of water a power plant uses (id.).

Finally, one commenter argued that the 10 percent safety factor used in developing the TPS was too high and that it should be reduced to 2 percent for dry cooled facilities and eliminated for facilities employing wet cooling (USGen Comments at 2).

2. Analysis and Findings

The Siting Board notes that the sole purpose of the TPS is to determine which generating facility proposals should be exempted from the portion of the Siting Board's review that focusses on the proponent's choice of generating technology. We therefore will adopt a proposed change to the Emergency Rule only if it will improve the effectiveness of the TPS by allowing it to distinguish between known fossil fuel generating technologies which meet the TPS as promulgated in the Emergency Rule, but which nonetheless have considerably different environmental impacts.

With regard to lead, the Siting Board notes that the Emergency Rule already includes a standard for lead[5].

With regard to CO_2, the Siting Board is not aware of any two generating technologies, both of which meet the TPS emissions levels as promulgated, but which are distinguishable by their CO_2 emissions. Moreover, we note that, although the Siting Board asked MASSPIRG and CWA to address this precise issue in written comments, they also were unable to identify two such generating technologies. We therefore do not add CO_2 to the list of criteria pollutants covered by the TPS. We will, however, continue to require proponents of all generating facilities filed with the Siting Board to offset a percentage of their CO_2 emissions.

Similarly, the Siting Board sees no benefit to reducing the "safety factor" incorporated into the TPS, as advocated by USGen. The safety factor was set at 10 percent to ensure consistent regulatory treatment of all facilities employing the generating technology on which

5 The emission standard for lead is at Table 2 of the Emergency Rule.

the TPS was based.[6] As USGen has not identified any other inferior generating technology that could pass the TPS as promulgated in the Emergency Rule, we see no need to alter the emissions levels in the TPS.

With regard to water use, the Siting Board did not include a specific water use standard in the TPS for several reasons. First, G. L. c. 164 § 69J¼ does not authorize specific water standards; it clearly states that the TPS is a set of emission standards for certain criteria pollutants and heavy metals. Second, the adoption of a water consumption standard as part of the TPS would not assist the Siting Board in distinguishing between two known generating technologies, both of which meet the TPS as promulgated but which are distinguishable by their water consumption. While certain oil or coal fired generating technologies may consume more water than gas-fired technologies, their air emissions do not pass the TPS; and while the water consumption of gas-fired combined cycle plants varies considerably from project to project, this variation is due primarily to decisions regarding cooling technology and backup fuel use, not generating technology. Third, the Siting Board believes that it is not possible to determine an appropriate level of generating facility water use without considering site-specific issues including: whether the project is going to use potable water, industrial water, or cleaned effluent; whether the project is a new use, or will be operating pursuant to a water permit issued for a previous similar use; and the acceptability of increased noise, visual, and land use impacts associated with cooling technologies that reduce water consumption.[7]

Finally, the Siting Board notes that it already conducts an in depth review of water use issues as part of its review process, and will continue to do so regardless of whether water use is made a part of the TPS. In a case where a high water use project is proposed, the Siting Board believes that applicant and Siting Board resources should be devoted to examining options to reduce the project's water consumption, including cooling technologies and other water-related design options, rather than to examining hypothetical (and potentially less clean) generating technology options.

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6 The purpose of the TPS is not to induce the proponent of a clean technology to be marginally cleaner by incorporating either added pollution control performance or added operating efficiency. Such a pollution reduction is, instead, the purpose of other elements of the Siting Board review, and reviews by other agencies, notably the MDEP.

7 Commenters also suggested establishing dual sets of air emission criteria based on water use, in order to avoid applying the "safety factor" to reflect water-saving technologies in cases where a project in fact would incorporate no such technology. As discussed above in response to USGen's comments relating to the safety factor, the Siting Board sees no benefit in further restricting the safety factor, which was intentionally set at ten percent to assure the consistent regulatory treatment of each generating technology.

B. Measurement and Testing

1. Summary of Comments

The Siting Board received comments recommending that: (1) the Siting Board set the emissions testing temperature at 59 degrees Fahrenheit, which is an industry standard, rather than at 50 degrees Fahrenheit (S&C Comments at 1); (2) the Siting Board specify testing protocols (id.; USGen Comments at 2); (3) the TPS specify that testing be conducted for base load operations (S&C Comments at 1); (4) the Siting Board exempt gas facilities from the need to test for heavy metals (CLF Comments at 2; S&C Comments at 1); and (5) the Siting Board require emission guarantees only when available from the equipment manufacturer (S&C Comments at 1; Sithe Comments at 3; USGen Comments at 3).

2. Analysis and Findings

With regard to the test temperature, the Siting Board notes that MDEP PSD permits vary in the test temperature specified, and that the "industry standard" of 59 degrees referenced in the S&C comment letter is by no means a mandatory temperature requirement for adequate test results. As noted previously, the Siting Board chose the test temperature of 50 degrees Fahrenheit to coincide with the temperature on which the emission limits in the MDEP PSD permit issued for the Dighton Power Project are based. The Siting Board believes that maintaining this consistency is important, and thus will retain a test temperature of 50 degrees Fahrenheit.[8]

With regard to testing protocols, the Siting Board agrees that the TPS should specify testing methods. Accordingly, the Siting Board amends Section 12.02 (1) of the Emergency Rule to read as follows: "Emission testing shall be conducted in accordance with the Massachusetts Department of Environmental Protection's "Guideline for Source Emission Testing" and in accordance with the U.S. Environmental Protection Agency tests as specified in 40 CFR Part 60, Appendix A; 40 CFR Part 60, Subpart GG; 40 CFR Parts 72 and 75; or in accordance with another methodology approved by the Massachusetts Department of Environmental Protection."

With regard to the comment that the TPS should be based on emissions at "base load", the Siting Board assumes that this means 100% load during ordinary operations. The Siting Board notes that Table I (criteria pollutant emission limits) already states this. The Siting Board will add this note to Table II (non-criteria pollutants).

With regard to testing for heavy metals, the Siting Board does not intend to require a

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8 The TPS does not prohibit applicants from converting test results from another temperature to that of 50 degrees F provided this is done in accordance with appropriate industry conversion procedures.

generating facility proponent to test for, model, or otherwise calculate emissions levels for pollutants which cannot, as a matter of chemistry, result from the combustion of the primary fuel proposed for that facility. We therefore revise the Emergency Rule to add the following language at the end of 980 CMR 12.02(1): "The Energy Facilities Siting Board may request copies of guarantees, work papers, or other documents to verify expected generating facility emissions; however, applicants proposing the use of fuel types that do not contain pollutants specified in the TPS and that when burned do not result in pollutants specified in the TPS, will not be required to provide modelling or testing results, guarantees, work papers or other similar documents with respect to those pollutants."

With regard to emission performance guarantees, the Siting Board revises the Emergency Rule at 980 CMR 12.02(1) to ensure that such performance guarantees need only be provided when available. The revision is as follows: "Such analysis shall include a summary of the proposed facility's expected emissions, a description of the modelling or other analyses used to derive the expected emissions, and where performance guarantees were used to derive the expected emissions and are available from the equipment manufacturer, a description of the performance guarantees".

C. Prospective versus Retroactive Application of the TPS

1. Summary of Comments

Three of the commenters, Sithe, S&G, and USGen, recommended that the language of the Emergency Rule be modified to provide that any future changes to the pollutant-specific emissions levels set forth in the TPS will not be applied retroactively. Sithe Comments at 3-4; USGen Comments at 3-4; S&C Comments at 1. In their comments, both Sithe and USGen offered proposed language to implement Sithe's suggestion that "a project's compliance with [the] TPS should be based on the TPS in effect at the time the petition is filed, regardless of future changes in the TPS." Sithe Comments at Appendix A; USGen Comments at 4.

2. Analysis and Findings

With respect to the application of the TPS to petitions filed with the Siting Board, G.L. c. § 69J¼ expressly provides that:

> . . . nothing in this chapter shall be construed as requiring the board to make findings regarding alternative generating technologies for a proposed generating facility whose expected emissions meet the technology performance standard in effect at the time of filing. (emphasis added).

The Siting Board agrees that including language in the TPS which tracks the statutory language of G.L. c. 164, § 69J¼ would be consistent with the Legislative intent that the TPS be applied prospectively, not retroactively. Inclusion of such language in the final regulation also would serve to prevent any potential confusion on this issue. Accordingly, the Siting Board hereby modifies the Emergency Rule at 980 C.M.R 12.03(3) to read as follows:

12.03: Technology Performance Standards

(3) Updating to the Technology Performance Standards. The Energy Facilities Siting Board will update the technology performance standards as necessary to reflect improvements in fossil fuel generating and control technologies. Any such updates or new technology performance standards will not apply retroactively to a proposed generating facility with expected emissions that satisfied the technology performance standards in effect on the date the applicant filed its petition for approval to construct the facility.

D. Other Comments

1. Summary of Comments

A number of commenters encouraged the Siting Board to expand the scope of the TPS emergency rulemaking to include matters other than the establishment of generating facility emissions levels for the purpose of streamlining the review of facility petitions filed with the Board. MASSPIRG, CWA, and the Sierra Club, for example, suggested that the emergency rulemaking be expanded to include the promulgation of "guidelines which spell out the criteria by which the Board will review the regional cumulative health and environmental impacts" of proposed generation facilities (CWA Comments at 2; MASSPIRG Comments at 1, 3-4; Sierra Club Comments at 1-2). MASSPIRG noted in its comments that it "is particularly troubled that the Siting Board omitted [these] statutorily-mandated guidelines . . . from this rulemaking" (MASSPIRG Comments at 1). MASSPIRG and the Sierra Club also suggested that the TPS be expanded to include specific criteria for evaluating facilities whose expected air emissions will exceed the levels set forth in the TPS, "which ensure that dirty power plants . . . are substantially disfavored . . ." and which would ameliorate "the comparatively vague statutory language which allows for an overly large amount of discretion by the Siting Board." Sierra Club Comments at 1; see also, MASSPIRG Comments at 1, 3-4.

2. Analysis and Findings

MASSPIRG's suggestion that the Siting Board has failed to include statutorily-mandated matters within its TPS rulemaking is not supported by the statutory language of G.L. c. 164, § 69J¼, the section of the Electric Restructuring Act to which MASSPIRG points in support of its position.

As noted earlier, the Electric Restructuring Act mandates that the Siting Board promulgate a TPS. G.L. c. 164, § 69J¼, second paragraph. Section 69J¼ also includes a sub-section authorizing (but not requiring) the Siting Board to establish petition filing guidelines, for the purpose of eliciting data from project applicants regarding the local and regional health and environmental impacts, including the cumulative impacts, of proposed generating facilities. G.L. c. 164, § 69J¼, fourth paragraph. While the Siting Board could have chosen to embark on a rulemaking that encompassed all of its authority under § 69J¼, or under the Restructuring Act as a whole,[9] the Board has elected instead to proceed at this time, by means of an emergency rulemaking, with promulgation of those regulations mandated by the Act.

The suggestion by MASSPIRG and Sierra Club that the Siting Board establish in this rulemaking new criteria for evaluating proposed facilities with emissions that will exceed the levels in the TPS, would have the Board expand the rulemaking beyond its noticed scope, a result that is incompatible with the requirements of Chapter 30A and with principles of due process. Moreover, such criteria were not included in the Emergency Rule, and thus were not noticed, because their inclusion was unnecessary. As discussed above, the sole purpose, and effect, of the TPS is to exempt those facilities whose emissions <u>will</u> satisfy the TPS, from the need to conduct an alternative technologies analysis. Upon promulgation of the TPS as a final rule, those facilities which cannot meet the TPS emission levels will remain subject to full Siting Board review, including an alternative technologies review, pursuant to G.L. c. 164, § 69J¼.

IV. <u>DECISION</u>

The Energy Facilities Siting Board hereby approves the Emergency Rule, as amended herein, for filing with the Secretary of State as a final regulation at 980 C. M. R. 12.00 ("Final Rule"). A copy of the Final Rule is attached hereto as Appendix A.

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9 The Electric Restructuring Act also provides the Siting Board with new authority to conduct a rulemaking to establish a minimum threshold for its jurisdiction over natural gas storage facilities. G.L. c. 164, § 69H.

APPROVED by the Energy Facilities Siting Board at its meeting of July 9, 1998, by the members and designees present and voting: Sonia Hamel, Acting Chair (for Trudy Coxe, Secretary of Environmental Affairs); James Connelly (Commissioner, DTE); Anna Blumkin (for David A. Tibbetts, Director of Economic Development); Nancy Brockway (Public Member).

Sonia W. Hamel

Sonia Hamel, Acting Chair
Energy Facilities Siting Board

DISSENT OF NANCY BROCKWAY

On July 7, 1998, the Board voted to approve its proposed rule on technical performance standards (TPS). These standards are required by the legislature, G.L. c. 164, Section 69J 1/4. This provision was added by the electric industry competition statute, passed last year. A key purpose of the provision, but not the only purpose in my view, is to provide a basis for streamlining the review process for those fossil-fuel plants that have state-of-the-art emissions control systems. I dissent from the adoption of the regulations as approved by the full Board, because the TPS standards approved July 7, 1998 do not contain important environmental protections required by the statute, and the Board as yet has no firm date for adopting these further protections.

CWA, MASSPIRG and Sierra Club argued that the statute requires the Board's performance standards to "reflect the best available and most efficient technology to control and reduce water withdrawals." G.L. c. 164, Section 69J1/4. The majority demurred from adopting such standards, stating in part that the statute does not in fact require such water control and withdrawal reduction standards. I do agree with the majority that there are complex interrelationships between site-specific factors relating to water control and withdrawal, as recited in the Board's order. These will take some time to sort through, and I was prepared to vote for the present draft of the TPS, so long as the Board makes a commitment to proceed with a rulemaking on the water control and withdrawal issues. However, the majority decision makes no such commitment, and rejects the necessity of doing so.

In my view, the statute is clear on its face: this Board must develop standards for water control and reduction of water withdrawals. I cannot join in a decision that relegates this obligation to a supporting role in the initiative to streamline the building of new gas-fired electric generation. Even within the key purpose of identifying fossil technologies that are state of the art on environmental issues, the Board's standards should distinguish between different gas-fired combined cycle technologies. That is, I read the word "technology" in the statute as comprising more than the choice of fuel, and thus the Board can choose to streamline the process for the type of fossil plant (today some form of gas fired generation) that best meets the entirety of environmental requirements, not simply the air emissions technical performance standards.

A number of the parties also urged the board to adopt guidelines pursuant to G.L. c. 164, Section 69J 1/4 to enable the Board to fulfill our statutory mandate to "review the regional cumulative health and environmental impacts" of proposed generating facilities. The majority again declined. In our deliberations it was argued, among other things, that the guidelines need not be rules formally adopted under Chapter 30A, that an informal process is underway to look at regional cumulative impacts, and that the guidelines are, in any event, intended by the legislature only to inform the filing requirements, not to set substantive decision rules. I disagree with the majority's interpretation of the statute. But even if the majority's reading is accurate, and we are not duty bound to issue substantive rules on the underlying policy issues of how to handle petitions to build facilities when a region could face cumulative health and environmental impacts, to do so would be the better course. We are embarking on a series of cases raising precisely these issues of cumulative regional impact. Far better to resolve the fundamental policy issues in a setting where all affected persons can have their say, than in an adjudicatory process focusing on only one project at a time.

For these reasons, I respectfully dissent.

July 15, 1998
Roslindale, MA.
Nancy Brockway
Public Member

980 CMR 12.00: TECHNOLOGY PERFORMANCE STANDARDS

Section

12.01: General

(1) Purpose. The purpose of 980 CMR 12.00 is to streamline the Energy Facilities Siting Board's review of petitions to construct generating facilities that have state of the art environmental performance characteristics.

(2) Scope. 980 CMR 12.00 applies to any application to construct a generating facility as that term is defined in M.G.L. c. 164, § 69G, filed for review pursuant to M.G.L. c. 164, § 69J¼. These regulations shall not in any way supersede or impair the authority of the Massachusetts Department of Environmental Protection with respect to such facilities.

(3) Statutory Authority. 980 CMR 12.00 is adopted pursuant to M.G.L. c. 164, § 69J¼, added by St. 1997, c. 164, § 210, which requires the Energy Facilities Siting Board to establish a technology performance standard for electric generating facility emissions, including, but not limited to, emissions of sulfur dioxide, nitrogen oxides, particulate matter, fine particulates, carbon monoxide, volatile organic compounds, and heavy metals.

12.02: Procedures

(1) Application of Technology Performance Standards. Any petition for approval to construct a generating facility that is filed for review pursuant to M.G.L. c. 164, § 69J¼ must include an analysis of the proposed facility's expected emissions of the criteria and non-criteria pollutants listed in 980 CMR 12.03. Such analysis shall include a summary of the proposed facility's expected emissions, a description of the modelling or other analyses used to derive the expected emissions, and where performance guarantees are available from the equipment manufacturer, a description of the performance guarantees. If the expected emissions of the proposed generating facility exceed the levels set forth in 980 CMR 12.03 for any pollutant or pollutants, the applicant also must provide the information listed in 980 CMR 12.02(2) as part of its petition.

The Energy Facilities Siting Board may request copies of guarantees, work papers, or other documents to verify expected generating facility emissions; however, applicants proposing the use of fuel types that do not contain pollutants specified in the TPS and that when burned do not result in pollutants specified in the TPS, will not be required to provide modelling or testing results, guarantees, work papers or other similar documents with respect to those pollutants.

Emissions testing shall be conducted in accordance with the Massachusetts Department of Environmental Protection's "Guideline for Source Emission Testing" and in accordance with U.S. Environmental Protection Agency tests as specified in 40 CFR Part 60, Appendix A; 40 CFR Part 60, Subpart GG; 40 CFR Parts 72 and 75; or in accordance with another methodology approved by the Massachusetts Department of Environmental Protection.

(2) Additional Information Requirements. An applicant proposing to construct a generating facility with one or more emissions in excess of the emission levels set forth in 980 CMR 12.03 must provide the following additional information with its petition:

(a) The applicant shall document the reliability of the proposed generation technology throughout the industry and evaluate the reliability of the proposed fuel supply in Massachusetts.
(b) The applicant shall provide the cost of the technology per megawatt hour (inclusive of capital costs, operating and fuel costs, and decommissioning costs) relative to other fossil fuel generating technologies.
(c) The applicant shall discuss how the proposed facility will enhance New England's energy mix and prevent overdependence on one or more fuel sources.
(d) The applicant shall provide information comparing the overall environmental impacts associated with the proposed facility with the overall environmental impacts of facilities using other fossil fuel generating technologies.

12.03: Technology Performance Standards

(1) Technology Performance Standards for Criteria Pollutants. The following are the technology performance standards for criteria pollutants:

Name of Pollutant	**Technology Performance Standard** (Pounds per Megawatt-Hour Burning Primary Fuel 100% base load at 50 degrees Fahrenheit)
Sulfur Dioxide	0.021
Nitrogen Oxides	0.120
Fine Particulates - PM10	0.081
Particulate Matter	0.081
Carbon Monoxide	0.077
Volatile Organic Compounds	0.035

(2) Technology Performance Standards for Non-Criteria Pollutants. The following are the technology performance standards for non-criteria pollutants:

Pollutant	**Technology Performance Standard (Pounds per Megawatt-Hour Burning Primary Fuel)**
Antimony	0.000171

Pollutant	Technology Performance Standard (Pounds per Megawatt-Hour Burning Primary Fuel)
Arsenic	0.00004
Beryllium	0.0000037
Cadmium	0.000033
Chromium	0.00033
Cobalt	0.00007
Copper	0.01
Lead	0.00045
Manganese	0.0026
Mercury	0.0000074
Nickel	0.0093
Nickel Oxide	0.012
Phosphorus	0.0023
Selenium	0.00004
Vanadium	0.000037
Vanadium Pentoxide	0.00012

(3) Updating to the Technology Performance Standards. The Energy Facilities Siting Board will update the technology performance standards as necessary to reflect improvements in fossil fuel generating and control technologies. Any such updates or new technology performance standards will not apply retroactively to a proposed generating facility with expected emissions that satisfied the technology performance standards in effect on the date the applicant filed its petition for approval

to construct the facility.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

Notice of Inquiry with Regard to the Siting Board's Standard of Review for Generating Facility Viability — EFSB 98-1.

FINAL DETERMINATION

Jolette Westbrook
Hearing Officer
August 17, 1998

On the Decision:
William S. Febiger
Diedre Shupp Matthews

For the reasons stated below, the Energy Facilities Siting Board hereby determines that it will not conduct a stand alone review of project viability for generating facilities filed pursuant to G.L. c. 164, §§ 69 H and J¼.

I. INTRODUCTION

A. Procedural History

On November 3, 1997, the Energy Facilities Siting Board ("Siting Board") announced its intention to issue a Notice of Inquiry ("NOI") seeking comments on the purpose and scope of its review of generating facility viability. The Siting Board indicated that it was undertaking this review in response to structural changes in the electric industry, noting that ".. it is appropriate at this time to reexamine [the Siting Board's] fundamental standard of review for viability in light of ongoing changes in the electric industry. The standard that was developed for NUGs selling capacity to utilities under long-term contracts may not be appropriate for merchant plants intending to sell power under short-term contracts or on the spot market". U.S. Generating Company, EFSB 96-4 at 74 (1997) ("Millennium Power Decision").

On November 25, 1997, pursuant to the Electric Restructuring Act ("Restructuring Act"), the statute governing the Siting Board and its scope of review regarding generating facility plants was amended.[1] The Restructuring Act altered the mandate of Siting Board review to state that the Siting Board "shall review only the environmental impacts of generating facilities, consistent with the commonwealth's policy of allowing market forces to determine the need for and cost of such facilities." St. 1997, c. 164, § 204.

On February 9, 1998, the Siting Board issued an NOI concerning the Board's viability review and permitted written comment to be filed prior to the public hearing.[2] On March 16,

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1 The effective date of the relevant portions of the Electric Restructuring Act was February 25, 1998.

2 Initial written comments were submitted by Associated Industries of Massachusetts ("AIM"); Cabot Power Corporation; Charles River Watershed Association ("CRWA"); Competitive Power Coalition of New England ("CPC"); Sandra Dam; Robin Fletcher; William Graban; the City of Haverhill; State Representative Barbara Hyland; Infrastructure Development Corporation ("IDC"); State Senator William R. Keating;
(continued...)

1998, the Siting Board held a public hearing at which 15 people, including developers, legislative personnel, private citizens, and an environmental organization provided oral comments.[3] At that time, the Siting Board established April 13, 1998 as the deadline for submission of final written comments.[4]

B. Scope of Decision

As outlined in the procedural history, above, this proceeding was deemed necessary prior to the enactment of the Restructuring Act, and was originally intended to review the need for and appropriate scope of the Siting Board's review of the viability of non-utility generators in light of changes in the electric industry. Between the time that the Siting Board directed staff to conduct this review and the time that it issued the NOI, the Restructuring Act was passed; the NOI that was issued therefore requested comment on the viability standard in light of both industry changes and the Restructuring Act.

Both in writing and at the March 16 public hearing, the Siting Board received many comments on the steps that it should take to implement the Restructuring Act and on the appropriate scope of its environmental review pursuant to the Act. In the first category, AIM urged the Siting Board to open the Technology Performance Standard rulemaking mandated by the second paragraph of G.L. c. 164, § 69J¼ (AIM Initial at 4). A number of commenters,

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Levitt, Conford & Associates; Patricia LoTurco; Reginald J. Macari; Massachusetts Citizens for Safe Energy ("Safe Energy"); Lisa A. Mosczynski; State Representative Douglas W. Petersen; Power Development Corporation ("PDC"); Sithe Energies, Inc. ("Sithe"); State representative Jo Ann Sprague; and U.S. Generating Company ("USGen").

3 Oral comments were given by IDC; PDC; Sithe; Jody Lerher, on behalf of Representative Douglas Petersen; Patricia LoTurco in her individual capacity and on behalf of Representative Barbara Hyland; CRWA; AIM; USGen; Competitive Power Coalition of New England; Karl Stieg; Louis Russo; Peter Longo; Michael Del Negro; and Diane Kozlowski.

4 Final written comments were submitted by AIM; Ethan D. Hoag; IDC; Representative Petersen; PDC; Sithe; and USGen.

including Representatives Petersen, Keating, and Sprague, asked the Siting Board to establish guidelines, authorized by the fourth paragraph of G.L. c. 164, § 69J¼, that would require applicants to submit sufficient data to enable the Siting Board to review such issues as local and regional land use impacts, and local and regional cumulative health impacts. Some of these commenters suggested that an advisory committee would be helpful in devising such guidelines (Hyland at 1; Petersen at 2; Keating at 1; Sprague at 1; Safe Energy at 1; LoTurco at 2; Dam at 1).

In the second category, a large number of commenters set forth the environmental issues of greatest concern to them, including air quality, water resources, wetlands issues, noise, safety, electro-magnetic fields ("EMF"), and public health issues such as occupational safety and the effects of using treated wastewater for cooling (CRWA at 1; Fletcher at 1-3; LoTurco at 2; Levitt; Mosczynski at 1,3; Dam at 1). Two commenters suggested that the Siting Board give preference to facilities using brownfield sites or to cogeneration facilities (Sithe Initial at 19; Dam at 1). Representative Petersen recommended that the Siting Board work with the Executive Office of Environmental Affairs ("EOEA") to develop its review of cumulative health impacts, and use Geographic Information System technology as appropriate. A number of commenters asked the Siting Board to address issues arising from clusters of power plants proposed in the same geographic area, including plants located in neighboring states (Fletcher at 1; Mosczynski at 1; Tr. at 74).

The Siting Board notes that these comments, while outside the scope of this proceeding, will be very useful to us as we move forward with our implementation of the Restructuring Act. While we cannot respond to each one in detail in this decision, we will address the main points briefly before turning to the primary subject of this proceeding.

The Siting Board appreciates the magnitude of the task before it in implementing the provisions of the Restructuring Act that apply to the review of generating facilities. We have now completed the promulgation of Technology Performance Standard regulations, which took effect in final form on August 7, 1998 and which can be found at 980 C.M.R. § 12.00. We are in the process of evaluating the need for additional rulemakings or other proceedings either to set forth filing guidelines or to clarify the scope of the Siting Board's review. Issues such as the appropriate scope of review for projects proposed at brownfield sites likely will be resolved through case precedent. We note that EOEA has a seat on the Siting Board, and Siting Board Staff and staff from EOEA will be working closely with each other to develop coordinated approaches to issues such as water supply.

Although many issues have yet to be resolved, there should be no doubt about the scope of the Siting Board's environmental review. In the decade since Northeast Energy Associates ("NEA") filed the first non-utility generating project ("NUG") in Massachusetts for review by the Siting Board, we have reviewed over 13 proposals for generating facilities. In each and every case, we have considered the full spectrum of environmental and community impacts -- air quality, water supply, wastewater, wetlands, land use, visual, noise, traffic, safety, EMF -- in determining whether the facility should be approved and, if so, what conditions should be imposed as part of the approval. When appropriate, this analysis has encompassed a review of the cumulative impacts of the proposed facility and other existing and planned uses on resources such as airsheds, watersheds, and the local noise environment.

Under the Restructuring Act, the Siting Board's broad environmental analysis has become the central focus of its review of generating facilities. The Siting Board is unequivocally committed to continuing this analysis, and to expanding it where necessary to address explicitly the local and regional land use impacts, local and regional cumulative health impacts, wetlands impacts, and visual impacts of proposed generating facilities.

The remainder of this decision addresses the subject noticed in the NOI -- namely, the purpose, scope, and fundamental standard of review for viability which the Siting Board uses in its review of petitions to construct power plants. Section II briefly reviews the development of the Siting Board's review of the viability of non-utility generators. Section III addresses the legal authority for a review of generating facility viability pursuant to G.L. c. 164, §§ 69H and J¼, and concludes that no such authority exists. Section IV addresses the policy implications of this legal conclusion. Section V summarizes the Siting Board's determination in this matter.

II. DEVELOPMENT OF SITING BOARD'S VIABILITY REVIEW

The Siting Board first undertook to review the viability of proposed generating facilities in Northeast Energy Associates, 16 DOMSC 335 (1987) ("NEA Decision"), its first review of a qualifying facility ("QF").[5] The NEA project was the first generating facility presented by a non-utility developer to the Siting Board for review, and the Siting Board consequently devoted a considerable portion of the NEA Decision to a discussion of the standard of review applicable to such facilities. With respect to cost and environmental impacts, the Siting Board established a four-part standard of review, stating that: " ... the Siting [Board] determines whether the project (1) is superior to a reasonable 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 and will therefore satisfy the previously identified need for additional power resources."[6] NEA Decision at 27. In reviewing the viability of the NEA project, the Siting Board considered the project's financing arrangements, its existing and proposed power sales agreements and its fuel supply strategy, and concluded that the NEA project was reasonably likely to be financed and constructed, and was likely to be a viable source of energy over the life of its contracts. Id. at 41-43.

The Siting Board's standard of review for non-utility generating facilities initially focused on viability over the life of QF contracts. See e.g., MASSPOWER, 20 DOMSC 301,

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5 The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3 (PURPA"), established a QF category consisting of non-utility electric cogenerators with the capability to generate both electric energy and useable steam. In order to qualify for QF status under PURPA, the cogenerator had to certify to the Federal Energy Regulatory Commission that it would sell a specified portion of its steam by-product in addition to its electric sales.

6 The Siting Board's statute implicitly assumed that generating facilities would be proposed in the context of a utility's long-range forecast and supply plan, and did not directly address the type of review that would be appropriate for a non-utility generating facility. However, the statute did provide for the review of non-utility oil facilities. A review of project viability was required for oil facilities, but not for facilities proposed by utilities. G.L. c. 164, §§ I and J (amended).

352 (1990); Altresco-Pittsfield, 17 DOMSC 351, 378 (1988). This standard of review was modified over time to accommodate projects that were not QFs and did not intend to hold long-term power sales contracts. See e.g., Enron Power Enterprise Corporation, 23 DOMSC 1, 89-90 (1991) ("Enron Decision"); Eastern Energy Corporation; 22 DOMSC 188, 295-299 (1991). It was also expanded over time to cover issues such as transmission interconnection agreements. Altresco Lynn, Inc., 2 DOMSB 1, 143 (1993); Enron Decision, 23 DOMSC at 101; West Lynn, 22 DOMSC 1, 69.

More recently, the Siting Board modified its standard of review to reflect "the need for flexibility, the expected shorter timeframe of [power purchase agreements] in a restructured electric industry, and the industry-wide shift away from long term gas supply contracts." Berkshire Power Development, Inc., 4 DOMSB 221, 343 (1996) ("Berkshire Power Decision"). At that time, the Siting Board also restated the purpose of its viability review, noting that a demonstration that "proposed facilities will remain competitive and reliable over time not only provides important security in meeting long term energy needs, but also provides assurances that such facilities will be as fully utilized over their planned lives as possible, thereby helping to minimize the future need for additional new construction and its associated cost and environmental impact." Id.

Currently, the Siting Board determines that a proposed non-utility generator is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 71; Dighton Power Associates, EFSB 96-3, at 24 (1997) ("Dighton Power Decision"); Berkshire Power Decision 4 DOMSB at 328. In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 71-72; Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 328.

III. LEGAL ANALYSIS AND DETERMINATION

The Siting Board developed its standard of review for the viability of non-utility generating facilities under G.L. c. 164, §§ 69H-J, as they were in effect prior to the Restructuring Act. The statute at that time made no explicit provision for the review of non-utility generating facilities; the Siting Board therefore developed a standard of review by adapting its precedent to the facts presented by the development, first of QFs, and then of independent power producers. However, in 1997, the legislature addressed this issue and set forth new procedures for the review of proposed generating facilities as part of the Restructuring Act. Therefore, as a threshold matter, we consider whether the viability of proposed generating facilities, as currently reviewed by the Siting Board, remains within our jurisdiction under the Restructuring Act.

A. Positions of the Parties

Commenters from the development community have raised four legal arguments in support of the proposition that the Siting Board has no legal authority to review the economic viability of proposed generating facilities. First, they note that G.L. c. 164, § 69H limits the Siting Board's review of proposed generating facilities to the environmental impacts of those facilities, and articulates a Commonwealth policy of allowing market forces to determine need and cost issues (PDC Initial at 4-5; PDC Final at 2; IDC Initial at 3-5; IDC Final at 2; USGen Initial at 3-5; Sithe Initial at 6; AIM Initial at 2; CPC at 2; Tr. at 159). Second, they argue that G.L. c. 164, § 69J¼ expressly prohibits the Siting Board from requesting cost and need data for generating facilities and conclude that the Siting Board cannot continue to use its current standard of review concerning viability, which relies in part on the evaluation of such data (IDC Initial at 3; PDC Initial at 4; Sithe Initial at 2,11; CPC at 2; USGen Initial at 4; AIM Initial at 3). Third, they note that G.L. c. 164, § 69J¼ enumerates specifically what the

Siting Board may review in a generating facility case, and that viability is not so enumerated (PDC Final at 3; Sithe Initial at 4). Finally, they assert that the intent of the Restructuring Act, as it applies to the Siting Board, is to create a streamlined process for proposed generation facilities, and that continuation of the viability review without any clear statutory authority would run counter to this intent (IDC Initial at 3; Sithe Final at 5; Tr. at 11 and 158).

The developers acknowledge that the Siting Board may still request certain types of information related to project viability for use in its environmental review. For example, PDC, IDC and Sithe indicate that the Siting Board could review plans for the construction, operation and maintenance of proposed facilities, including the experience and track record of the providers, in order to satisfy environmental concerns (PDC Initial at 7, 9; IDC Initial at 6-7; Tr. at 108-109). Similarly, IDC notes that a proponent's plans for interconnection with the interstate gas pipeline system are likely to have environmental impacts (Tr. at 110-112).

In response to the suggestion that the siting statute still permits a review of the reliability of proposed generating facilities, Sithe argued that G.L. c. 164, § 69H requires the Siting Board to provide for "a reliable energy supply" by "review[ing] only the environmental impacts of generating facilities" (Tr. at 116-117). PDC suggests that the Siting Board could generally evaluate the reliability of new technologies, although PDC and Sithe both suggest that major technological innovation is usually tested on a small scale before being implemented in projects the size of those reviewed by the Siting Board (Tr. at 115-122).

No other commenter addressed the legal issues in written comments. In response to questioning, Jody Lehrer, speaking for Representative Peterson, expressed the opinion that any parts of the viability standard that related to cost and need were no longer germane to the review of power plants (Tr. at 78). In response to further questioning, she indicated that the Siting Board might be able to look at reliability in the context of a generating facility review (Tr. at 86).

B. Analysis

In reviewing petitions to construct generating facilities, the Siting Board is guided by G.L. c. 164, § 69H, which states the general purpose and scope of that review, and by G.L.

c. 164, § 69J¼, which provides detailed direction on procedures, information requirements, and necessary findings. G.L. c. 164, § 69H, as revised by the Restructuring Act, directs the Siting Board to "review only the environmental impacts of generating facilities consistent with the commonwealth's policy of allowing market forces to determine the need and cost of such facilities." G.L. c. 164, § 69H. Prior to the Restructuring Act, the Siting Board had statutory authority to consider the need for and cost of proposed generating facilities, as well as their environmental impacts. The Restructuring Act thus requires a clear shift in the focus of the Siting Board's review of generating facilities. In this context, it requires the Siting Board to eliminate any part of its viability review that focuses on need and cost.

In addition to this general proscription on reviewing the need for and cost of generating facilities, G.L. c. 164, § 69J¼ prohibits the Siting Board from requesting data regarding the need for and cost of proposed generating facilities. This section is specific; it states that "[n]othing in this chapter shall be construed as requiring the board to make findings regarding the need for, or cost of..." a generating facility. G.L. c. 164, § 69J¼. Further, while G.L. c. 164, § 69J¼ authorizes the Siting Board to develop guidelines relative to the information that it requests from petitioners, the section states that "these guidelines shall not require any data related to the necessity or cost of the proposed generating facility." Id.

Based on the general and specific exclusion of cost and need issues from the Siting Board's review of generating facilities, there is a compelling argument that the first test of the Siting Board's viability review -- whether the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned -- is now beyond the scope of the Siting Board's mandate. Project financing is driven almost exclusively by projections of project cost and demand for power, and the ability to construct a project depends on receipt of financing and the project's financial and other arrangements with the construction contractor. Similarly, the cost aspect of the second part of the viability test -- whether the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project -- also is now clearly beyond the permitted scope of Siting Board review. Therefore, for the Siting Board to continue to assess such issues would be contrary to the Commonwealth's policy as articulated by the legislature.

The commenters also make a more general argument that the scope of the Siting Board's review of generating facilities is narrowly defined, and that the Siting Board has no authority to go beyond that scope. In this regard, G.L. c. 164, § 69H directs the Siting Board to "review only the environmental impacts of generating facilities". In addition, § 69J¼ explicitly outlines specific criteria for the approval of proposed generating facilities. The statute states that the Siting Board shall approve a petition to construct a generating facility if the Siting Board determines that the petition meets the following requirements: (1) the description of the proposed generating facility and its environmental impacts are substantially accurate and complete; (2) the description of the site selection process used is accurate; (3) the plans for the construction of the proposed generating facility are consistent with current health and environmental polices of the commonwealth and with such energy policies as are adopted by the commonwealth for the specific purpose of guiding decisions of the board; (4) such plans minimize the environmental impacts consistent with the minimization of costs associated with the mitigation, control, and reduction of environmental impacts of the proposed facility; and (5) if the petitioner was required to provide information on other fossil fuel generating technologies, the construction of the proposed generating facility on balance contributes to a reliable, low-cost, diverse, regional energy supply with minimal impacts on the environment. G.L. c. 164, § 69J¼.

G.L. c. 164, § 69J¼ clearly provides no explicit authority for a stand-alone review of project viability. Given the specificity with which § 69J¼ sets forth the scope of the Siting Board's review, accepted rules of statutory construction suggest that if the legislature had intended the Siting Board to review viability issues, it would have so stated.[7] Therefore, it would be difficult to support the position that viability issues, such as whether or not a project is financiable and whether a project is likely to meet its performance deadlines, remain valid issues for Siting Board inquiry under the new legislation. The Siting Board concludes that §§ 69H and 69J¼, taken together, are intended to limit its review of generating facilities to the

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7 The Siting Board notes that, in drafting § 69J¼, the legislature chose not to carry over language from § 69J that authorizes a review of viability for oil facilities.

topics enumerated in § 69J¼. Accordingly, we concur with the commenters that the Restructuring Act no longer allows the Siting Board to continue to use its current standard of review relative to viability.

Finally, the Siting Board agrees with the commenters that the intent of the Restructuring Act, as it relates to the Siting Board's review of generating facilities, is to streamline the review by focusing it on environmental issues and leaving issues of need and cost exclusively to the marketplace. The Siting Board therefore concludes that the purposes of the Restructuring Act would not be well served by continuing its review of generating facility viability in the absence of explicit legislative authorization of such review. It is important to note that prior to the Restructuring Act, the Siting Board had a mandate to "provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost." Former G.L. 164, § 69H. Therefore, under the former statute, the Siting Board's examination of viability had legal underpinnings in that such an examination helped to provide the Siting Board with assurance that generating facilities pending before the Board were likely to be constructed and able to meet the need for additional energy resources. The Siting Board is now required to "provide a reliable energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost" by reviewing "only the environmental impacts of generating facilities, consistent with the commonwealth's policy of allowing market forces to determine the need for and cost of such facilities." G.L. c. 164, § 69H. In the absence of any authority to review the need for generating facilities, the prior legal rationale for the viability analysis no longer exists.

In summary, the Siting Board concludes that it has no statutory authority pursuant to G.L. c. 164, §§ 69H and J¼ to continue its review of the economic viability of generating facilities. The Siting Board also concludes that much of its existing standard of review for viability covers subjects that have been explicitly placed outside its scope of review by the Restructuring Act. Consequently, the Siting Board determines that it will not conduct a stand-alone review of project viability for generating facilities filed pursuant to G.L. c. 164, §§ 69H and J¼.

In making this determination, the Siting Board notes that certain topics that we have previously investigated as part of our viability review, e.g., the experience and track record of construction and operation and maintenance ("O&M") contractors, may be directly linked to environmental issues. We do not interpret the Restructuring Act as precluding us from continuing to request such information from petitioners, unless the information falls squarely within the subjects of need or project cost. While we take seriously the directive to streamline our review of generating facilities by leaving the issues of need and cost for the market to determine, we will not compromise our environmental review. This issue is discussed further in Section IV, below.

IV. POLICY ANALYSIS

In Section III, the Siting Board concluded that it has no statutory authority pursuant to G.L. c. 164, §§ 69H and J¼ to continue its review of the economic viability of generating facilities, and that much of its existing standard of review for viability covers subjects that have been explicitly placed outside its scope of review by the Restructuring Act. Consequently, the Siting Board determined that it will not conduct a stand-alone review of project viability for generating facilities filed pursuant to G.L. c. 164, §§ 69H and J¼. This section clarifies the scope of this determination and addresses a number of related policy issues raised in participant comments.

A. Positions of the Parties

The policy comments of AIM and the development community primarily address the need for the Siting Board's current review of economic viability in a restructured electric industry. USGen argues that the Siting Board originally undertook a review of the viability of QFs and other independent power projects to ensure that such facilities would "be reliable sources of power if utilities were to reasonably rely on them to meet their captive customer's needs" (USGen Initial at 2). USGen suggests that, due to structural changes in the market, the Siting Board's oversight is no longer needed to ensure system reliability (id. at 2).

USGen and other developers also argue that the financial community conducts ongoing and intensive reviews of the viability of merchant projects that go well beyond the Siting

Board's review of financing, contracts, and fuel supply strategy both in detail and in scope. (PDC Initial at 6; IDC Initial at 5; Sithe Initial at 12, 18; Tr. at 16-19). They argue that since market participants and regulators have a shared interest in ensuring the viability of proposed generating facilities, there is no need for the Siting Board to attempt to duplicate the financial market's review (Sithe Final at 4; IDC Final at 4; Tr. at 33-36). They note that an administrative review of viability, as currently conducted by the Siting Board, places a significant amount of commercially sensitive information in the public record, and may increase the ultimate cost of power to consumers (PDC Initial at 6; IDC Initial at 5-6; Sithe Initial at 22; USGen Initial at 10-11).

The developers specifically address concerns raised by staff that the elimination of the Siting Board's viability review could result in the more frequent approval and construction of plants that prove commercially unsuccessful. First, they argue that projects of this magnitude do not receive financing and go to construction without undergoing internal and external reviews of project viability that are much more detailed than any that the Siting Board could reasonably conduct (PDC Final at 3; IDC Final at 3; Tr. at 16-17). Second, they note that the Siting Board historically has approved projects which ultimately did not go forward, and note the inherent difficulty of trying to predict the success of a market-driven project based on a snapshot of the project's finances and draft contracts at a relatively early stage in project development. (PDC Initial at 6; IDC Initial at 5-6; Sithe Initial at 22). Third, they assert that the new generation of power plants being proposed in Massachusetts is unlikely to be closed or sit idle, because new plants can produce power at a lower cost than most existing plants (PDC Final at 4; Tr. at 53).

Comments received from the Legislature, the environmental community, and the public at large focus more on the need for a review of the environmental or resource viability of proposed generating facilities than on the Siting Board's current review of financing, contracts, and fuel supply. For example, CRWA argues that the long-term viability of any generating facility is linked to the sustainability of the resources upon which it draws, and particularly upon the availability and stress on water resources (CRWA at 1; Tr. at 139-145). Similarly, Representative Peterson recommends that the term "viability" be redefined to clearly include environmental impacts, if this is necessary to ensure that the Siting Board conducts a comprehensive review of the environmental impacts of proposed facilities (Petersen Initial at 1-2).

A number of commenters also express concern about the environmental impacts of a plant that is constructed and then fails; some suggest that this concern be addressed by requiring developers to post operational and post-closure bonds sufficient to remediate a site if a plant fails (Tr. at 133, 144; Petersen Final at 2; Sprague at 1; Keating at 1; LoTurco at 1; Mosczynski at 2). In response, the developers argue that the Siting Board has no legal authority to impose bonding requirements (PDC Final at 7; IDC Final at 6-7).

B. Analysis

The Siting Board concludes that its traditional review of financing strategies, construction and O&M contracts, and fuel supply arrangements is both inconsistent with its role under the Restructuring Act and of limited value given the current structure of the electric market. The original purpose of the viability review was to ensure that a non-utility generating facility would provide a reliable, low-cost supply of energy over the life of its QF contracts. At that time, the viability review was critical to consumer protection since, if approved, the NUGs would enter into long-term power contracts with utilities, which would rely on the NUGs for capacity and would pass the cost of the contracts, and of replacement power if necessary, on to their captive ratepayers. In the emerging competitive market for power, NUGs will no longer be able to pass their costs on to captive customers through long-term contracts with utilities; the viability review therefore no longer serves the same consumer protection function.

The viability review also was originally intended to "ensure that actual energy production benefits will flow from the project that outweigh any adverse environmental impacts associated with siting and operating the facility", so as to deter the construction of commercially unsuccessful plants that are underutilitzed or eventually abandoned. NEA Decision at 27. The Siting Board acknowledges that a power plant, once constructed, has land use and visual impacts that continue even if the plant is no longer in operation, and that communities that agree to host power plants may be legitimately concerned about the disposition of the project site when the plant reaches the end of its useful life. However, the Siting Board is persuaded that its current review of financing, contracts, and fuel supply, even if it were still permissible, is no longer an effective tool to address this concern. At best, this review assures the Siting Board that a proposed project is credible at a relatively early stage in project development. However, it is clear from the record in this case that investors conduct an extensive review of the financial viability of a proposed project before committing to construct it; such a review provides the best assurance that a project that is not credible will not be financed and constructed, regardless of whether the Siting Board reviews its economic viability. In addition, the question of whether and how frequently a proposed facility likely will be dispatched in ten years' time depends largely on the future demand for power and the facility's cost-competitiveness relative to other plants; these issues are both clearly outside the Siting Board's scope of review, and difficult to predict with any accuracy.

While the Siting Board thus concludes that its current review of a generating facility's financing, contracts, and fuel supply plans has outlived its usefulness, it has no intention of abandoning its review of the environmental viability of such facilities. The Siting Board agrees with CRWA and other commenters that resource availability is critical to the success of any power plant, and that an analysis of the carrying capacity of water and other resources is an important element of its review of proposed generating facilities. The Siting Board historically has considered these issues in the context of its analysis of the environmental impacts of a proposed facility, and will continue to do so under G.L. c. 164, § 69J¼.

The Siting Board also acknowledges the possibility that an apparently viable generating facility will fail commercially, although the record suggests that modern combined-cycle plants are likely to be dispatched frequently due to their efficiency and relatively low operating costs, and therefore are unlikely to be underutilized or prematurely abandoned. Certain commenters have proposed operational or post-closure bonding to ensure that resources are available to remediate generating facility sites if the facilities are abandoned. It is not immediately clear whether the Siting Board has the legal authority to require such bonding as a condition of approval. However, even if such authority exists, the Siting Board could exercise it only on a case-by-case basis, and only if it determined, after reviewing the cost of bonding, the likelihood of abandonment, the potential for hazardous wastes, other potential remedies, and related issues, that bonding was necessary to "minimize the environmental impacts of [the proposed facility] consistent with the minimization of the costs associated with the mitigation, control and reduction of the environmental impacts of the proposed generating facility." G.L. c. 164, § 69J¼.

Finally, the Siting Board notes that in the past there has been some overlap between the information needed to conduct the viability review and the information needed to evaluate the environmental impacts of a proposed generating facility. For example, a company's plans for interconnecting with the natural gas pipeline system and the electric grid, and its plans for disposing of its wastewater, have been necessary components of our review of project viability; however, they also are important to our review of the land use impacts, off-site construction impacts, waste water impacts, and EMF impacts of a proposed facility, as well as to our review of the site selection process. In the future, the Siting Board will continue to seek information necessary to its environmental review, such as interconnection routes and the capacity of the local waste water treatment facility, but will no longer seek information related primarily to viability, such as the proponent's financial arrangements with the Independent System Operator or wastewater treatment facility, or its purchasing strategy for natural gas.

V. SUMMARY

In Section III, above, the Siting Board concluded that it has no statutory authority pursuant to G.L. c. 164, §§ 69H and J¼ to continue its review of the economic viability of generating facilities. The Siting Board also concluded that much of its existing standard of review for viability covers subjects that have been explicitly placed outside its scope of review by the Restructuring Act.

Accordingly, based on the above, the Siting Board will not conduct a stand alone review of project viability for generating facilities filed pursuant to G.L. c. 164, §§ 69H and J¼.

ATTACHMENT A

COMMENTERS

Submitted Initial Written Comments

Representative Douglas Petersen

Representative Jo Ann Sprague

Senator William Keating

Cabot Power Corporation

Infrastructure Development Corporation

Power Development Company

Sithe Energies, Inc.

U.S. Generating Company

Associated Industries of Massachusetts

Charles River Watershed Association

Competitive Power Coalition

Haverhill City Council

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Associated Industries of Massachusetts

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Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of August 13, 1998, by the members and designees present and voting. Voting for approval of the Draft Determination as amended: Janet Gail Besser (Chair, EFSB\DTE); James Connelly (Commissioner, DTE); W. Robert Keating (Commissioner, DTE); Sonia Hamel (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); and David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development).

Janet Gail Besser

Janet Gail Besser
Chair

Dated this 17th day of August, 1998

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of ANP Bellingham Energy Company for Approval to Construct a Bulk Generation Facility and Ancillary Facilities in Bellingham, Massachusetts	)))))))	EFSB 97-1

FINAL DECISION

M. Kathryn Sedor
Hearing Officer
August 18, 1998

On the Decision:
Jeffrey Brandt
William S. Febiger
Enid Kumin
Peter Mills

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LIST OF ABBREVIATIONS

Abbreviation	Explanation
AALs	Annual allowable ambient limits
ABB	Asea Brown Boveri, Inc.
ACS	Advanced Cycle System
AFB	Atmospheric fluidized bed coal technology
AGT	Algonquin Gas Transmission Company
Algonquin	Algonquin Gas Transmission Company
ANP	ANP Bellingham Energy Company
ANP Bellingham	ANP Bellingham Energy Company
BACT	Best available control technology
BCC	Bellingham Conservation Commission
bmt	Billion metric tons
BECo	Boston Edison Company
Btu/kwh	British thermal units per kilowatt hour
CAAA	Federal Clean Air Act Amendments of 1990
Cabot	Cabot Power Corporation
CC	Combined Cycle
CCWCs	Circulating cooling water coolers
CELT	Capacity, Energy, Loads and Transmission (yearly reports prepared by NEPOOL)

CEMs	EPA's Continuous Emissions Monitoring System
CG	Integrated Coal Gasification
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)
CO	Carbon monoxide
CO_2	Carbon dioxide
Company	ANP Bellingham Energy Company
CT	Generation Combustion Turbine
CRWA	Charles River Watershed Association
dBA	A-weighted Decibel
DCR	Debt coverage ratios
DEIR	Draft Environmental Impact Report
Department	Department of Telecommunications and Energy
DOE	The United States Department of Energy
DOT	The United States Department of Transportation
$/kWh	Dollars per kilowatt-hour
DSM	Demand side management
EMF	Electric and magnetic fields
ENF	Environmental Notification Form
EPA	The United States Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPRI	Electric Power Research Institute
ERCs	Emission reduction credits
ERP	Emergency Response Plan

FEIR	Final Environmental Impact Report
FERC	Federal Energy Regulatory Commission
Firm gas supply	The assumption used in analyzing fuel costs that gas supply from the wellhead to the proposed facility will be firm
Franklin	Town of Franklin
Franklin Initial Brief	Town of Franklin Initial Brief
Franklin Reply Brief	Town of Franklin Reply Brief
GCC	Gas-fired combined cycle unit
GEP	Good Engineering Practice
GIS	Geographic Information Systems Mapping
gpd	Gallons per day
GTF	NEPOOL Generation Task Force
HRSG	Heat recovery steam generator
IDC	Infrastructure Development Corporation
IDLH	Immediately Dangerous to Life or Health
IPP	Independent power producer
IRR	Internal Rate of Return
kV	Kilovolt
L_{90}	The level of noise that is exceeded 90 percent of the time
LAER	Lowest Achievable Emission Rate
lbs/MMBtu	Pounds per million British thermal units
L_{dn}	EPA's day-night noise level
L_{eq}	24-hour equivalent noise level

LOS	Level of service -- a measure of the efficiency of traffic operations at a given location
MAAQS	Massachusetts ambient air quality standards
MA DEM	Massachusetts Department of Environmental Management
MassGIS	Massachusetts Geographic Information System
MA WMA	Massachusetts Water Management Act
MCZM	Massachusetts Coastal Zone Management
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
mG	Milligauss
mgy	Million gallons per year
MHC	Massachusetts Historical Commission
MHD	Massachusetts Highway Department
MW	Megawatt
NAAQS	National ambient air quality standards
NEA	Northeast Energy Associates
NEPCO	New England Power Company
NEPOOL	New England Power Pool
NHESP	Natural Heritage and Endangered Species Program
NMLs	Noise Monitoring Locations
NOx	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NP	National Power
NPV	Net present value

NRC	Nuclear Regulatory Commission
NSPS	New source performance standards
NSR	New source review
NU	Northeast Utilities
NUG	Non-utility generator
O_3	Ground-level ozone
O&M	Operation and maintenance
OSP	Ocean State Power
PAL	Public Archaeology Laboratory, Inc.
Pb	Lead
PC	Pulverized coal facility
PFB	Pressurized fluidized bed coal facility
PM-10	Particulates
PPAs	Power purchase agreements
PSD	Prevention of significant deterioration
PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3
QF	Qualifying facility
RAA	NEPOOL 1996 Resource Adequacy Assessment
RFP	Request for Proposals
ROW	Right-of-way
SACTI	Seasonal/Annual Cooling Tower Plume Impact model
SCR	Selective Catalytic Reduction System
SILs	Significant impact levels

Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
SO_2	Sulfur dioxide
SOx	Sulfur oxides
SPCCP	Spill Prevention, Control and Countermeasure Plan
SS-RFP	Site Selection RFP
TAG	EPRI Technical Assessment Guide
TELs	Threshold effects exposure limits
TGP	Tennessee Gas Pipeline Company
Town	Town of Bellingham
tpy	Tons per year
USGen	U.S. Generating Company
USGS	United States Geological Survey
USGS Study	1991 Report by USGS, Water Resources and Aquifer Yields in Charles River Basin, Massachusetts
VOCs	Volatile organic compounds
ZBA	Zoning Board of Appeals

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of ANP Bellingham Energy Company to construct a net nominal 580-megawatt bulk generating facility and ancillary facilities at the proposed site in Bellingham, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

ANP Bellingham Energy Company ("ANP Bellingham" or "Company") has proposed to construct a natural gas-fired, combined-cycle, electric generating facility with a nominal net electrical output of 580 megawatts ("MW") in the Town of Bellingham, Massachusetts ("project") (Exh. BEL-1, at 1-5). The proposed project would be located on an approximately 20-acre footprint located within an approximately 125-acre parcel of undeveloped land (id.). The Company has proposed that natural gas would be delivered to the project via a new, 14-inch, 1.1-mile pipeline to be constructed by Algonquin Gas Transmission Company ("Algonquin" or "AGT"), which would extend from Algonquin's existing pipeline facility in Bellingham to the project site (id. at 1-6 to 1-7). Electric power generated by the proposed project would be supplied for transmission through interconnection to an existing 345 kilovolt ("kV") New England Power Company ("NEPCo") transmission line which traverses the proposed site (id. at 1-7).

In addition to its natural gas and electrical interconnections, the proposed project includes the following major components and structures: two single shaft power islands, each of which consists of an Asea Brown Boveri ("ABB") GT-24 combustion turbine, a heat recovery steam generator ("HRSG"), a steam turbine and an electric generator, a dry low nitrogen oxides ("NOx") combustion system and a selective catalytic reduction ("SCR") system for control of nitrogen oxides; two dry condenser cooling towers; and two 180-foot exhaust stacks. Additional project components include a 1.5-million-gallon demineralized water storage tank, a 1.0-million-gallon raw water storage tank, and two 14,000-gallon ammonia storage tanks.

The project is designed with the capacity to operate at its standard baseload level, and to augment its electricity production through steam injection to meet higher demand levels (id. at 1-6). Each of the project's two combustion turbines will generate approximately 180 MW of electricity (210 MW with steam augmentation), and the exhaust heat of the turbine will be recaptured to produce steam and drive the steam turbine, producing an additional 95 MW of electricity (85 MW with steam augmentation) (id.).

The Company's proposed site for the project is located in an industrially zoned area in Bellingham (id. at 1-8). The site is predominantly wooded, and is presently undeveloped (id.). Maple Street in Bellingham, which is primarily residential in nature, borders the site to the east and south (id.). Route 495 borders the site to the west (id. 1-13). Property controlled by the U.S. Army Corps of Engineers along the Charles River forms the site's northern boundary (id.).

ANP is an affiliate of American National Power, Inc. and was formed in April 1997 for the development of the proposed project (id. at 1). American National Power is an affiliate of National Power, plc, ("NP") which is the leading electric power generating company in the United Kingdom and owns and/or operates approximately 24,100 MW of generating capacity world-wide with 7,400 MWs located in eight countries outside the United Kingdom including the United States (id.).

B. Jurisdiction

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

As a wholesale electric generator with a design capacity of approximately 580 MW, the Company'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, the Company's proposal to construct an electric interconnection, a gas interconnection and other structures at the site fall within the third definition of "facility" set forth in G.L. c. 164, § 69G, which states that a facility is:

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

C. Procedural History

On May 27, 1997, the Company filed with the Siting Board[1] a petition to construct and operate a nominal net 580-megawatt natural gas-fired, combined-cycle power plant and ancillary facilities in Bellingham, Massachusetts.[2] The Siting Board docketed the petition as EFSB 97-1. On July 10, 1997, the Siting Board conducted a public hearing in Bellingham and on August 14, 1997, the Siting Board conducted a public hearing in Franklin, Massachusetts.[3] In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearing and adjudication.

Timely petitions to intervene were filed by: Kenneth and Judith Barnett; the Town of Bellingham Conservation Commission; ("Bellingham Conservation Commission"); Linda L. Blais; Trisha and Peter Dorfman; Henry E. Faenza; Frank E. Falvey; Jon Fish; Susan M. Flaherty; the Town of Franklin ("Franklin"); Paul F. Gibbs; Joseph A. Goulart;

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1 Prior to September 1, 1992, the Siting Board's functions were effected by the Energy Facilities Siting Council ("Siting Council"). See Acts of 1992, Chapter 141. As the Siting Council was the predecessor agency to the Siting Board, the term Siting Board should be read in this Decision, where appropriate, as synonymous with the term Siting Council.

2 The Company amended its petition on June 27, 1997.

3 The public hearing in Franklin was held pursuant to ANP's request after it became aware at the Bellingham public hearing that it had not mailed notice of the public hearing to property owners in Franklin within one half mile of the primary site. As a result, the intervention deadline for Franklin property owners was extended to August 21, 1997.

James P. LaPlante; Gary B. McAlister; Northeast Energy Associates ("NEA"); New England Power Company and Massachusetts Electric Company ("NEPCo/MECo"); Ocean State Power ("OSP"); Ross P. Thayer; Judith T. and John D. Webb, Jr.; and Mary Jo Yasatovich. Timely petitions to participate in the proceeding as an Interested Person were filed by: Cabot Power Corporation ("Cabot"); Frances Fabricotti; and U.S. Generating Company ("USGen"). In addition, the Siting Board received late filed petitions to intervene from: Mark A. Brady on September 25, 1997; the Wrentham Research Group ("WRG") on October 2, 1997; Robert B. Lovett on October 9, 1997; and Infrastructure Development Corporation ("IDC") on November 10, 1997. ANP filed an opposition to the petitions of IDC, NEA and OSP, and filed a motion to impose certain conditions on those persons granted status to intervene and participate in this proceeding. USGen and NEA filed a response to ANP's motion for conditions.

The Hearing Officer allowed the Bellingham Conservation Commission, the Town of Franklin and NEPCo/MECo to participate as full parties (Hearing Officer Procedural Order, September 24, 1997). Frank Falvey and Paul Gibbs were granted limited intervention status with respect to environmental and associated cost issues, and issues concerning need. In addition, Kenneth and Judith Barnett, Linda Blais, Joseph A. Goulart, James P. LaPlante, Gary B. McAlister, and Mary Jo Yasatovich were granted status as limited intervenors with respect to environmental and associated cost issues (id.).[4] NEA was granted status as a limited intervenor with respect to water withdrawal issues and was granted status as an interested person relative to the other issues in this case (id.). Status as an interested person was granted to OSP, Trisha and Peter Dorfman, Henry Faenza, Jon Fish, Susan Flaherty, and John and Judith Webb, Cabot, Frances Fabricotti and USGen (id.). The Hearing Officer also denied ANP's motion for conditions (Hearing Officer Procedural Order, September 24, 1997). Further, the Hearing Officer denied the late-filed petitions of Robert B. Lovett, Ross P. Thayer and WRG (Hearing Officer Procedural Orders, September 24, 1997, October 16,

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4 Paul F. Gibbs and Mary Jo Yasatovich subsequently withdrew from this proceeding.

1997, and November 4, 1997).[5] The Hearing Officer also denied Mr. Brady's and IDC's petitions to intervene, but allowed Mr. Brady and IDC to participate as interested persons (Hearing Officer Procedural Order, December 16, 1997).

On September 23, 1997, the Company filed a motion requesting that it be permitted to withdraw its alternative site from consideration by the Siting Board in this proceeding. On December 16, 1997, this motion was granted (see section I.D, below).

The Siting Board conducted sixteen days of evidentiary hearings commencing on January 28, 1998 and ending on March 31, 1998. The Company presented the testimony of thirteen witnesses: Daniel Peaco of LaCapra Associates, who testified as to the need for the proposed project; Douglas Smith of LaCapra Associates, who testified as to alternative technologies; Robert Charlebois, project director for ANP, who testified as to viability, site selection, water, carbon dioxide ("CO_2") mitigation and other issues; Steven Pedrick, construction manager for the proposed project, who testified as to design issues, operation, maintenance, visual, traffic and safety issues; Robert Haupt, vice president of the Company, who testified as to viability, cost and steam augmentation issues; Daniel Lorden, project director of ANP, who testified on interconnection issues; Robert Kasle, manager of fuel procurement for the Company, and Geoffrey Mitchell of Merrimack Energy, who jointly testified as to the project's fuel acquisition strategy; Frederick M. Sellers, vice president of Earth Tech, who testified as to site selection, air, and visual issues; David Keast, an independent acoustical engineer, who testified as to noise impact and noise mitigation issues; Lynn Gresock, project manager for Earth Tech, who testified as to traffic, visual, wetlands and other environmental issues; Dr. William H. Bailey, President of Bailey Research Associates, Inc., who testified as to electric and magnetic field issues ("EMF"); and Richard Friend, hydrogeologist for Earth Tech, who testified on water supply and resource issues.

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5 Thereafter, Mr. Thayer filed a motion for reconsideration. His motion was denied on the basis that the Company withdrew its alternative site from the Siting Board review process. Thus, there was no longer any possibility that Mr. Thayer would be substantially and specifically affected by the proposed project (Hearing Officer Procedural Order, November 4, 1997).

Intervenor Goulart presented the testimony of two witnesses: Interested Person Mark A. Brady, and Patricia LoTurco, a member of the Wrentham Research Group.

On April 17, 1998, Mark Brady filed two motions to re-open the record. The motions were subsequently denied by the Hearing Officer.

The Hearing Officer entered more than 1000 exhibits into the record consisting primarily of information and record request responses. The Company entered more than 80 exhibits into the record; the Bellingham Conservation Commission submitted more than 100 exhibits into the record; the Town of Franklin entered more than 62 exhibits into the record; NEA submitted more than 20 exhibits into the record; and Mr. Goulart entered more than 20 exhibits into the record. On April 21, 1998, initial briefs were filed by the Company, the Bellingham Conservation Commission and the Town of Franklin. Also on that date, a joint initial brief was filed by Joseph Goulart and Mark Brady. On April 27, 1997, reply briefs were filed by the Company and the Town of Franklin.

D. Scope of Review

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct facilities, the Siting Board requires applicants to justify generating facility proposals as follows. First, the Siting Board requires the applicant to show that additional energy resources are needed. U.S. Generating Company, EFSB 96-4, at 6 (1997) ("Millennium Power Decision"); Dighton Power Associates, EFSB 96-3, at 5 (1997) ("Dighton Power Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA Decision") (see Section II.A, below). Second, the Siting Board requires the applicant to show that, on balance, its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability. Millennium Power Decision, EFSB 97-4, at 6; Dighton Power Decision, EFSB 96-3, at 5; NEA Decision, 16 DOMSC at 364 (see Section II.B, below). Third, the Siting Board requires the applicant to show that its project is viable. Millennium Power Decision, EFSB 97-4, at 6-7; Dighton Power Decision, EFSB 96-3, at 6; NEA Decision, 16 DOMSC at 364 (see Section II.C, below).

Fourth, the Siting Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and, where an alternate site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. Millennium Power Decision, EFSB 96-4 at 7; Dighton Power Decision, EFSB 96-3, at 6; NEA Decision, 16 DOMSC at 343 (see Section III.A, below).

In cases where no alternative site is noticed, the applicant must demonstrate that its proposed facilities' siting plans are superior to alternatives, and that its proposed facility is sited at a location that minimizes costs and environmental impacts while ensuring supply reliability. Specifically, the applicant must show (a) that it has examined a reasonable range of practical facility siting alternatives by meeting a two-pronged test: it must establish that it (1) 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, and (2) identified at least two potential facility sites with some measure of geographic diversity; (b) that its proposed facility is sited, designed and mitigated in a manner that will minimize cost and environmental impacts; and (c) that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability (see Section III.B, below).[6]

In the present case, the Siting Board allowed ANP to withdraw its noticed alternative site.[7] Consequently, we apply the standard of review applicable to those cases where the applicant has not noticed an alternative site for its proposed project.

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6 The legal and policy reasons for allowing project applicants the option of noticing only a preferred site, as opposed to a preferred and an alternative site, are set forth in a recent Siting Board Advisory Ruling. See, Request of Infrastructure Development Corporation for an Advisory Ruling (Advisory Ruling, September 16, 1997) ("IDC Advisory Ruling").

7 The legal and policy analysis set forth in the IDC Advisory Ruling served as the basis for granting of ANP Bellingham's request to withdraw its noticed alternative site in this proceeding. See, Hearing Officer Procedural Order Re: Motion to Withdraw Noticed Alternative Site, EFSB 97-1, December 16, 1997.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

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

In City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"), the Supreme Judicial Court ("Court") concluded that the Siting Board's finding that New England needed additional energy resources for reliability purposes was inadequate in light of the statutory mandate that an energy supply must be necessary for the Commonwealth. 413 Mass. at 489. In addition, the Court noted that, although the Siting Board had argued that its mandate was to ensure an adequate energy supply at minimum cost, "[e]nsuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth (emphasis added)." 413 Mass. at 490, citing G.L. c. 164, § 69H.

In response to the Court's directive in City of New Bedford, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with its statutory mandate -- to implement the Commonwealth's energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost -- in Eastern Energy Corporation (on Remand), 1 DOMSB at 421-423 (1993) ("EEC (remand) Decision").

With respect to the issue of regional need versus Massachusetts need, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability (id. at 422). The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration (id.). Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not linked to individual utilities by power purchase agreements ("PPAs") (id. at 416). The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3, 4. Accordingly, the Siting Board found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision, 1 DOMSB at 417.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. Millennium Power Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 8; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Millennium Power Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 8; Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. Millennium Decision, EFSB 96-4, at 9; Dighton Power Decision, EFSB 96-3, at 9; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes that such analyses of need would be consistent with its statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. Millennium Power Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 8-9; Enron Power Enterprise Corporation, 23 DOMSC 1, 49-62 (1991) ("Enron Decision").

Further, while acknowledging that G.L. c. 164, § 69H requires the Siting Board to ensure a necessary supply of energy for Massachusetts, the Siting Board interprets this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources,[8] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. Millennium Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 8-9; Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985) ("1985 MECo/NEPCo Decision"). In doing so, the Siting Board fulfills the requirements of G.L. c. 164, § 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in the New England Power Pool ("NEPOOL").

The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. Millennium Power Decision, EFSB 96-4, at 10; Dighton Power Decision, EFSB 96-3, at 9; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the Court's reminder in City of New Bedford that its statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth for them to be considered in support of a finding of Massachusetts need. 1 DOMSB at 418. See also Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost-effective

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

qualifying facility ("QF")[9] resources to its utilities' supply mix. NEA Decision, 16 DOMSC at 358. In that case, the Siting Board also found (1) that a signed and approved PPA between a QF and a utility constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes prima facie evidence for the need for additional energy resources for reliability purposes (id.). Thus, in cases where a non-utility developer sought to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board has required the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. MASSPOWER, Inc., 21 DOMSC 196, 200 (1990); MASSPOWER, Inc., 20 DOMSC 1, 19-23, 32 (1990) ("MASSPOWER Decision"); Altresco-Pittsfield Decision, 17 DOMSC at 366-367. Two 1995 decisions of the Court, however, bring into question further reliance on such prima facie evidence in this and future cases.[10]

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

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9 The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3 ("PURPA"), established a QF category consisting of non-utility electric cogenerators with the capability to generate both electric energy and useable steam. In order to qualify for QF status under PURPA, the cogenerator had to certify to the Federal Energy Regulatory Commission ("FERC") that it would sell a specified portion of its steam by-product in addition to its electric sales.

10 In Point of Pines Beach Association v. Energy Facilities Siting Board, the Court noted the Siting Board's statutory requirement to make an independent finding of Commonwealth need, a finding that could not be premised solely on the existence of signed and approved PPAs. 419 Mass. 281, 285-286 (1995) ("Point of Pines"). Referencing its decision in Point of Pines, the Court vacated a final decision of the Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) ("Attorney General").

energy supply of the Commonwealth. Millennium Power Decision, EFSB 96-4, at 12; Dighton Power Decision, EFSB 96-3, at 9-10; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision"). Therefore, consistent with the Siting Board's precedent and reflecting the directives of the Court in City of New Bedford, Point of Pines, and Attorney General, the Siting Board here reviews the need for the proposed project for reliability, economic and environmental purposes.

2. Reliability Need

The Siting Board has found that it is appropriate to consider the need for capacity beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See Millennium Power Decision, EFSB 96-4, at 12; Dighton Power Decision, EFSB 96-3, at 10; West Lynn Decision, 22 DOMSC at 14, 33-34. The Siting Board has acknowledged that the longer time frame is potentially useful regardless of whether need has been established for the first year of proposed operation. If need has been established for the first year, the longer time frame helps ensure that the need will continue over a number of years, and is not a temporary aberration. If need has not been established for the first year of proposed operation, a demonstration of need within a limited number of years thereafter may still be an important factor in reaching a decision as to whether a proposed project should go forward. Thus, for the purposes of this review, the Siting Board finds that it is appropriate to consider explicitly need for the proposed facility during the 2000 to 2006 time period.

a. New England

ANP asserted that there is a need for at least 580 MW[11] of additional energy resources

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11 The Company indicated that the proposed project's summer capacity rating with steam augmentation is 534 MW, its winter rating with steam augmentation is 616 MW, and its nominal average rating is 579 MW (Exh. BEL-1, at 2-21, n.29). The Company indicated that it focused on summer peak load because the summer season, rather than the winter season, drives the need for capacity (Tr. 1, at 80, 84). The Siting Board here evaluates need based on the average annual capacity rating, inclusive of steam augmentation. Use of the average annual rating is conservative in the case of a

in New England beginning in the year 2000 and beyond (Exh. BEL-1, at 2-21). In support, the Company presented a series of forecasts of demand and supply for the region based primarily on the 1997 forecasts and other data published by NEPOOL (id. at 2-5; Exh. HO-RR-12). The Company indicated that it compared its demand and supply forecasts to produce a series of need forecasts (Exh. BEL-1, at 2-20 to 2-21).

The Company stated that the forecasts of summer demand and supply are developed from individual forecasts of several underlying factors which include: (1) unadjusted peak loads; (2) utility-sponsored demand side management ("DSM") resources available on peak; (3) NUG netted from load; (4) supply resources; and (5) required reserve margin (id. at 2-3). The Company stated that it developed "adjusted" summer peak load by subtracting the DSM and NUG factors from the unadjusted peak load; the adjusted peak load then was multiplied by a factor reflecting the required reserve margin to yield a forecast of total capacity requirements (id. at 2-9). The Company stated that projected supply resources were then subtracted from the total capacity requirements in each year of the forecast to provide a forecast of the magnitude and need for new energy resources (id. at 2-20).

In the following sections, the Siting Board reviews the Company's demand forecasts, including its demand forecast methods and estimates of DSM savings over the forecast period, and the Company's supply forecasts, including its capacity assumptions and required reserve margin assumptions. The Siting Board then analyzes a series of need forecasts.

(1) Demand Forecasts

(a) Description

ANP presented forecasts of unadjusted summer peak load and DSM savings derived from information contained in the 1996 and 1997 Capacity, Energy, Loads and Transmission ("CELT")[12] reports published by NEPOOL (Exhs. HO-N-2, at 1; HO-RR-13).[13]

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summer need analysis.

12 The Company indicated that the CELT report includes: (1) high, reference and low forecasts of unadjusted load for summer and winter peaks; (2) a forecast of DSM savings; (3) a forecast of NUG netted from load (i.e., power from NUG units located

To develop forecasts of adjusted load, the Company combined each of these peak load forecasts with (1) the 1997 CELT report forecast of NUG netted from load, and (2) one of three forecasts of DSM savings based on the 1997 CELT report forecast of DSM savings (Exhs. BEL-1, at 2-8 to 2-9 and app. D; HO-RR-13).

i) Demand Forecast Methods

The Company presented a base case unadjusted peak load forecast, derived directly from the 1997 NEPOOL CELT report reference forecasts of unadjusted load for summer peak ("1997 CELT forecast") (Exh. HO-RR-13). The Company stated that NEPOOL uses an econometric model based on a number of New England economic variables to forecast trends in the economy and resulting levels of energy consumption and peak demand (Tr. 1, at 17). The Company asserted that the reference forecast provides a reasonable projection of regional demand (id.).[14] The Company also presented the 1996 CELT report high case ("CELT high case") and low case ("CELT low case") demand forecasts, which are based on optimistic and

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at the site of an end-user which displace power that could be sold by a NEPOOL utility, and which is not available for sale outside the site); and (4) a reference forecast of adjusted load for summer and winter peaks, derived by deducting the forecasts of DSM savings and NUG netted from load from the unadjusted reference load forecast (Exh. HO-N-2, at 1, 2).

13 The Company originally provided information based on 1996 CELT Report and the NEPOOL 1996 Resource Adequacy Assessment ("RAA") (Exh. BEL-1, sec. 2). ANP indicated that the 1996 RAA is a forecast of capacity needed to maintain power supply reliability in New England and that the 1996 CELT report is the primary source of data and assumptions used in the 1996 RAA (id. at 2-5). During the course of the hearings, the Company provided information based on the 1997 CELT report.

14 The Company indicated that the 1997 CELT forecast was derived by updating the 1996 CELT forecast in the short-term (1997 to 2000) only (Exh. HO-N-3). The Company indicated that the 1997 CELT forecast is higher than the 1996 CELT by 100 to 226 MW for the years 1997 through 1999 and by 328 MW for the year 2000, and then identical to the 1996 CELT forecast for the remainder of the forecast period (Exhs. HO-N-1, at 2; HO-N-2, at 2). The Company indicated that forecasts for NUG netted from load and DSM are identical in the two forecasts (Exhs. HO-N-1, at 2; HO-N-2, at 2).

pessimistic economic forecasts, respectively, to illustrate the full range of uncertainty in the peak load (Exhs. BEL-1, at 2-8 to 2-9 and app. D; Tr. 1, at 18-19).[15]

ii) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the current forecast of company-sponsored DSM savings used in NEPOOL's 1996 CELT report;[16] (2) a high DSM scenario which is 110 percent of the base scenario; and (3) a low DSM scenario, which is 90 percent of the base DSM scenario (Exh. BEL-1, at 2-9). The Company stated that, historically, NEPOOL has overestimated DSM savings but that more recent NEPOOL forecasts have been lower and closer to actual savings (id.).

iii) Adjusted Load Forecasts

The Company stated that to develop forecasts of adjusted load, the 1997 CELT unadjusted summer base case load forecast was combined with the (1) the 1997 CELT report forecast of NUG netted from load, and (2) three forecasts of DSM savings (Exh. HO-N-4.2). In addition, the 1996 CELT unadjusted summer high and low case forecasts were each combined with (1) the 1997 CELT forecast of NUG netted from load, and (2) the base DSM scenarios (Exhs. HO-N-1, at 2; HO-N-2, at 2; BEL-1, at app, D). Thus, the Company presented five forecasts of adjusted summer peak load.

(b) Analysis

The Siting Board previously has acknowledged that the CELT report generally can provide an appropriate starting point for resource planning in New England, and has accepted the use of CELT forecasts for the purposes of evaluating regional need in previous reviews of

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15 ANP stated that NEPOOL estimates the CELT low case demand forecast to have a 90 percent chance of being exceeded and the CELT high case demand forecast to have a ten percent chance of being exceeded (Exh. BEL-1, at 2-8).

16 The Company indicated that the 1996 CELT report forecast of DSM also was used in the 1997 CELT report (Exhs. HO-N-1, at 1; HO-N-2, at 1).

proposed NUG facilities. Millennium Power Decision, EFSB 96-4, at 16; Berkshire Power Decision, 4 DOMSB at 272; NEA Decision, 16 DOMSC at 354. In addition, the Siting Board has relied primarily on the more recent available forecasts in its analysis of need. See Berkshire Power Decision, 4 DOMSB at 257.

Here, the Company derived an unadjusted base case summer demand forecast and base case DSM scenario directly from the 1997 CELT forecast, which is the most recent CELT forecast. The Company derived two additional DSM scenarios from the base DSM scenario. The Company adjusted the unadjusted base case forecast by base, high and low DSM scenarios, for a total of three adjusted forecasts.

In addition, the Company provided the CELT high case demand forecast and CELT low case demand forecast as extreme demand forecasts, in order to test the sensitivity of the results of analysis of the base case forecast. As noted above, NEPOOL assigns a low probability of occurrence to each of these forecasts. Consistent with previous Siting Board decisions (see, e.g., Millennium Power Decision, EFSB 96-4, at 17; Cabot Decision, 2 DOMSC at 274), the Siting Board finds that these forecasts represent a sensitivity analysis of varying economic assumptions rather than forecasts of regional demand.

Overall, the Company has presented one base case forecast adjusted by three forecasts of DSM. Given uncertainties in forecasting demand, the Siting Board has previously found that it is reasonable to include a range of forecasts in a company's reliability need analysis. See, e.g., Millennium Power Decision, EFSB 96-4, at 17; Berkshire Power Decision, 4 DOMSB at 261, n.23. However, as noted above, the Siting Board has acknowledged the value of the CELT report for regional resource planning and has accepted the use of CELT forecasts for the purpose of evaluating regional need. In addition, in reviewing need forecasts, the Siting Board has placed more weight on the base case forecast. Berkshire Power Decision, 4 DOMSB at 274. Here, the Company has provided the most recent CELT forecast as a base case forecast and also has provided high and low forecasts for the purpose of demonstrating the range of potential demand. Therefore, the Siting Board finds that it is reasonable, for purposes of this review, to rely on one base case forecast for summer peak load.

Accordingly, the Siting Board finds that the 1997 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2000 and beyond.

The Company also provided three forecasts of utility-sponsored DSM -- a base case scenario, which is NEPOOL's current forecast of Company-sponsored DSM savings, a low DSM scenario which discounts NEPOOL's projected DSM growth rates by ten percent, and a high DSM forecast, which inflates NEPOOL's projected DSM growth rates by ten percent. As noted above, although NEPOOL historically has overestimated DSM savings, the more recent NEPOOL forecasts have been lower and closer to actual savings. The Company's symmetrical ten percent adjustment of NEPOOL's DSM forecast is consistent with NEPOOL's trend to the successive lowering of its DSM forecasts and consistent with the DSM scenarios accepted by the Board in its most recent generating facility decision. See, Millennium Power Decision, EFSB 96-4, at 17-18.

Accordingly, for purposes of this review, the Siting Board finds that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In sum, the Siting Board has accepted one forecast of summer peak load. In addition, the Siting Board has accepted three forecasts of DSM -- a base case, low case and high case. Therefore, the Siting Board here accepts three forecasts of adjusted summer peak load for the purposes of this review.

(2) Supply Forecasts

(a) Description

i) Capacity Assumptions

ANP presented three supply scenarios -- base, high and low -- based in large part on the supply resources included in the 1997 CELT report (Exhs. BEL-1, at 2-10 to 2-20;

HO-RR-12).[17] The Company stated that it updated the 1997 NEPOOL supply forecast to reflect changes in the regional supply not included by NEPOOL (Exh. HO-RR-12, at 1 to 3). Specifically, beginning in 2000, the Company deducted the capacity of: (1) the Maine Yankee unit (794 MW), retired in July 1997; (2) the Middletown 1 unit (66 MW), and the Norwalk Harbor 10 unit (12 MW), both reactivated from deactivated reserve in 1996 as a temporary response to the Millstone unit outages;[18] (3) the South Meadow 15 unit (42 MW), installed as a temporary response to the Millstone unit outages but since removed from the site; (4) the English 7 and 8, and Somerset Steam 5 units (141 MW), deactivated units which are included as reactivated units starting in 2002 even though the 1997 CELT report indicates that the owners have not decided whether to reactivate; and (5) the Bridgeport Harbor 1 unit (81 MW), which will be removed consistent with plans for new facility development at the site (Exhs. BEL-1, at 2-6; HO-N-8.1; HO-RR-3; HO-RR-3 supp.; HO-RR-12, at 1 to 3). ANP also added the capacity of: (1) the Wyman 1-3 units (223 MW);[19] (2) the Indeck Jonesboro unit (49 MW), returned to service in 1998 following deactivation; and (3) the Devon 11-14 units (125 MW), installed as a temporary response to the Millstone outages and assumed by NEPOOL to retire in 2001 but recently granted permanent operating permits (Exhs. HO-RR-3; HO-RR-12 at 1 to 3; HO-RR-12, supp.).

The Company stated that, to reflect uncertainties in future capacity in its supply scenarios, it then adjusted the updated 1997 NEPOOL forecast by varying projections of:

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17 The Company indicated that NEPOOL supply resources include all existing plants, external purchases and sales, and committed utility and non-utility generation owned or contracted by NEPOOL member utilities that is under construction and/or fully licensed (Exhs. BEL-1, at 2-10; HO-N-2, at 3, 97-100).

18 The Company noted that, although the Middletown 1 unit is 44 years old and the Norwalk Harbor 10 unit is a 32-year-old gas turbine unit, the 1997 CELT Report shows both continuing to remain in service indefinitely (Exhs. HO-RR-3; HO-RR-3 supp.).

19 ANP indicated that the 1997 CELT report specifies that these units are operating and will be retired at the end of 1999, but notes that they are candidates for life extension (Exh. HO-RR-12, supp.). ANP assumed that these units would continue to operate as they are similar to other older oil steam units (id.). Therefore, the Company added them to the supply forecast beginning in 2000 (id.).

(1) the availability of existing fossil fuel-steam units; (2) the availability of existing nuclear units; and (3) the capacity of new projects currently being developed (id.; Exhs. BEL-1, at 2-10 to 2-20; HO-RR-12.3). ANP asserted that the CELT supply forecast overstates expected future capacity from existing nuclear units and fossil fuel steam units because it is simply a tabulation of all existing generating units based on their design or contract life without consideration of uncertainty in future availability (Exh. BEL-1, at 2-10). Specifically, the Company stated that the 1997 CELT report assumes (1) the continued operation of all active nuclear units in the region for the full terms of their current operating licenses even though these units are old and are facing significant regulatory, technical and economic issues, and (2) the limited retirement of existing fossil fuel steam units that have been in operation for more than 25 years even though 1,500 MW will be at least 40 years old by 2000 and 3,200 MW will be at least 40 years old by 2005 (id. at 2-10 to 2-16).[20]

With respect to nuclear units, ANP stated that the Millstone 1 unit (641 MW) has been out of service since 1995 and that the Millstone 2 and 3 units (2030 MW) have been out of service since 1996 (Exh. HO-N-8.1). ANP stated that Northeast Utilities ("NU") has indicated its expectations that the Nuclear Regulatory Commission will approve the re-start of the Millstone 2 and 3 units by mid-1998 and has also indicated that it will examine whether to restart the Millstone 1 unit later in 1998 (Exh. HO-N-8.2). ANP stated that it is increasingly likely that the Millstone 1 unit will be retired (id.). ANP noted that the Connecticut Department of Public Utility and Control recently issued an order finding the Millstone 1 unit not used and useful based on NU's deferral of maintenance on this unit in favor of the Millstone 2 and 3 units and thus removed the Millstone 1 unit from rate base (id.).

ANP stated that the older fossil fuel steam units will typically require increased expenditures for operations and maintenance ("O&M") and performance degradation due to their age and potential capital costs to comply with Phase II of the Clean Air Act

[20] The Company indicated that the 1996 CELT report assumes that of the 10,249 MW of coal-steam, oil-steam and oil/gas-steam units currently operating, 10,026 will be available in 2007 and beyond (Exh BEL-1, at 2-16).

Amendments of 1990 ("CAAA") (id. at 2-16).[21] The Company explained that many of these expenditures likely will be difficult to justify under restructuring due to competition from new generation technology which has significant efficiency, economic and environmental advantages (id. at 2-16 to 2-17).

In addition, the Company stated the 1997 CELT supply forecast does not include the capacity from all proposed new generating facilities that have reached significant licensing completion (Exh. HO-RR-6).[22] The Company indicated that three new proposed generating facilities are fully licensed and under construction -- Berkshire Power Development (265 MW), Dighton (170 MW), and Bridgeport Harbor, Connecticut (520 MW) (id.; Exh. HO-RR-12, at 1 to 2). The Company also indicated that two new proposed generating facilities have reached significant licensing completion -- Tiverton, Rhode Island (250 MW), and Millennium (360 MW) (Exhs. HO-RR-6; HO-RR-12, at 1 to 2).[23] The Company noted that there are development, licensing, financing and construction uncertainties that could affect the successful completion of projects not fully licensed and under construction (Exh. BEL-1, at 2-20).

For the base supply scenario, the Company assumed reductions in the 1997 CELT forecast capacity based on retirement of (1) the Millstone 1 unit (641 MW), and

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21 ANP indicated that Phase II of the CAAA will require additional NOx reductions to be implemented by 1999 (Exh. BEL-1, at 2-16 to 2-17).

22 The Company indicated that the 1997 CELT supply forecast includes the capacity of the following categories of projects under development: (1) construction complete, not yet in operation; (2) under construction, has complete regulatory approval; and (3) under licensing consideration (Exhs. BEL-1, at 2-19 to 2-20; HO-N-11; HO-N-2, at 97-99).

23 The Company indicated that there are a number of other new generating units, including the ANP unit in Blackstone, that are proposed in the region which are not included in the supply forecast because have not reached significant licensing completion (Exhs. BEL-1, at 2-19; HO-RR-6; Tr. 1, at 58 to 61).

(2) 25 percent of the fossil-fired steam capacity that is at least 40 years old (386 MW in 2000 increasing to 908 MW in 2006)[24] (Exhs. HO-N-9.1; HO-RR-5; HO-RR-12.3). In addition, the Company added 100 percent of the capacity of the new generating units that are fully licensed and under construction (955 MW) and 50 percent of the new generating units that have reached significant licensing completion (305 MW) (Exhs. HO-RR-6; HO-RR-12.3).[25]

For the high supply scenario, the Company assumed that: (1) the Millstone 1 unit would be returned to service (641 MW); (2) ten percent of the fossil-fired steam capacity that is at least 40 years old would be retired (154 MW in 2000 increasing to 545 MW in 2006); (3) 100 percent of the capacity of the new generating units that are fully licensed and under construction would come on-line as scheduled (955 MW); and (4) 80 percent of the new generating units that have reached significant licensing completion would come on-line as scheduled (488 MW) (Exhs. BEL-1, at 2-17; HO-RR-12.4). For the low supply scenario, the Company assumed that: (1) the Millstone 1 and 2 units would be retired (1,512 MW); (2) 50 percent of the fossil-fired steam capacity that is at least 40 years old would be retired (772 MW in 2000 increasing to 1816 MW in 2006); (3) 100 percent of the capacity of the new generating units that are fully licensed and under construction would come on-line as scheduled (955 MW); and (4) 20 percent of the new generating units that have reached significant licensing completion would come on-line as scheduled (122 MW) (Exhs. BEL-1, at 2-17; HO-RR-12.4).

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24 The Company stated these assumptions are similar to those adopted by the Siting Board in previous cases (Berkshire Power Decision, 4 DOMSB at 270), except that no specific unit has been used as a proxy for these retirement in any of the cases. (Exh. BEL-1, at n.21). ANP noted that in the Berkshire Power Decision, the Salem Harbor 1-3 units were used as a proxy for such retirements in the base case (id.).

25 The Company stated that capacity imports to New England are significantly strained by transmission constraints and that it was not aware of any new transmission line projects that would bring more power into New England (Exh. HO-RR-62; Tr. 3, at 71).

ii) Reserve Margin

The Company indicated that it adopted NEPOOL's most current projections of required reserve margins which are set forth in the September 1994 NEPOOL document, "1994 Annual Review of NEPOOL Objective Capability and Associated Parameters" (Exh. BEL-1, at 2-9). ANP stated that, in that document, NEPOOL specifies required reserve margins of 14.8 percent of adjusted peak load in 2000 and 15 percent of adjusted peak load starting in the year 2001 (id.; Exh. HO-N-7.1, at 6).[26]

(b) Analysis

The Company has presented a base supply scenario which was based on the 1997 CELT report supply forecast, updated to reflect adjustments for actual, planned and likely changes to NEPOOL supply. In addition, to account for uncertainties in future availability, the Company then adjusted the updated 1997 NEPOOL forecast by varying projections of three categories of capacity to develop base, high and low supply scenarios. Here, the Siting Board considers the reasonableness of the Company's assumptions.

The Company's updates to the 1997 CELT report supply forecast included adjustments to reflect likely long-term status of units put in service as a temporary response to the Millstone outages. The Company deleted the capacity of older units that were reactivated from deactivated reserve and added the capacity of units put into service that received permanent operating permits. For purposes of this review, the Siting Board accepts the Company's assumptions.

As noted above, in the base case supply scenario, the Company assumed that 25 percent of the fossil fuel steam units that have been in operation for more than 25 years would be retired -- 386 MW in 2000 increasing to 908 MW in 2006. The Siting Board notes that it is reasonable to conclude that a portion of the units operating beyond retirement guidelines will be retired beginning in 2000, especially in light of CAAA requirements that

26 ANP noted that the 15 percent reserve margin assumes that the Hydro-Quebec contract is not counted as firm capacity (Tr. 1, at 72). Mr. Peaco stated that if Hydro-Quebec were treated as firm capacity the required reserves would be higher (id. at 73).

are likely to take effect in 1999. In previous reviews the Siting Board has accepted assumptions that one unit operating beyond NEPOOL's guidelines for retirement, or a like amount of capacity, would be retired. See, Millennium Power Decision, EFSB 96-4, at 24; Berkshire Power Decision, 4 DOMSC at 270. The capacity reduction here for the year 2000 is consistent with previous reviews. Therefore, the Siting Board accepts the Company's assumption regarding retirement of fossil fuel steam units operating for more than 25 years.

The Company also assumed that the Millstone 1 unit would be retired in the base case supply scenario. The record demonstrates that the Millstone 1 unit has been out of service since 1995, that NU has not decided whether to restart the unit, that NU has deferred maintenance on the unit and that the Connecticut Department of Public Utility and Control has removed the unit from rate base. Therefore, for purposes of this review, the Siting Board accepts the Company's assumption of the retirement of the Millstone 1 unit. In addition, the Siting Board recognizes that it is appropriate to account for additional NUG resources that may commence operation during the forecast period. Here, the Company included 100 percent of the capacity of those units that are fully licensed and under construction and 50 percent of the capacity of those units that have reached significant licensing completion. The Company's criteria for including new proposed units is reasonable given the development, licensing, financing, and construction uncertainties that could affect the successful completion of units that are not fully licensed and under construction. Therefore, for purposes of this review, the Siting Board accepts the Company's assumptions regarding the inclusion of newly proposed units in the base case supply scenario.

Accordingly, the Siting Board finds that the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need. In addition, the Siting Board finds that the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and therefore that the low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need. The Siting Board further finds that the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and therefore that the high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need.

Finally, with respect to reserve margins, the Company used NEPOOL's projected reserve margins for the years 2000 and 2001 and reasonably assumed that the reserve margins would remain at the projected values for the year 2001 in the years 2000 through 2006. Accordingly, consistent with recent Siting Board decisions, the Siting Board finds that the reserve margins projected by the Company are appropriate for purposes of this review.

(3) Need Forecasts

(a) Description

The Company developed nine need forecasts by adjusting the 1997 CELT summer peak load forecasts by each of three DSM scenarios, and combining each of the resulting three adjusted demand forecasts with three supply forecasts (Exh. HO-RR-13.2, 13.3, 13.4). Of these nine need forecasts, seven demonstrate a sustained need for at least 580 MW of capacity in 2000 and all demonstrate a sustained need for at least 580 MW of capacity in 2001 (id.).[27,28] See Table 1, below.

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27 The Company also presented need analyses based on the CELT high case demand forecast and CELT low case demand forecast, each adjusted by the base case DSM forecast and the base supply forecast (Exh. BEL-1, app. D). The need analysis based on the CELT high case demand forecast shows a need for 580 MW in 2000 while the need analysis based on the CELT low case demand forecast shows a need for 580 MW in 2006 (id.; Exh. HO-RR-12.3).

28 The Siting Board notes that all need cases which incorporate the base and low supply scenarios show a need in 2000 for both the proposed facility and the Company's proposed facility in Blackstone.

Table 1

RANGE OF REGIONAL NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(342)	(1,397)	(2,837)
1997 CELT	Base	(510)	(1,565)	(3,005)
1997 CELT	Low	(678)	(1,733)	(3,173)

2001

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(651)	(1,770)	(3,315)
1997 CELT	Base	(825)	(1,944)	(3,489)
1997 CELT	Low	(998)	(2,117)	(3,662)

Source: Exhs. HO-RR-13.3, 13.4, 13.5.
Note: Capacity deficits are shown in parentheses.

(b) Analysis

In considering the Company's forecasts of summer and winter peak load, the Siting Board has found that the 1997 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2000 and beyond. In considering the Company's DSM forecasts, the Siting Board has found that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and

(3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need. In addition, the Siting Board has found that the reserve margins projected by the Company are appropriate for the purposes of this review.

The capacity positions under the summer and winter need forecasts based on the 1997 CELT summer peak load forecast for the years 2000 and 2001 are shown in Table 1, above. Of these nine need forecasts, seven demonstrate a sustained need for at least 580 MW of capacity in 2000 and all demonstrate a sustained need for at least 580 MW of capacity in 2001. Accordingly, the Siting Board finds that there is a sustained need for 580 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000.

b. Massachusetts

The Company asserted that there is a need for new capacity in Massachusetts by the year 2000 (Exh. BEL-1, at 2-25). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based primarily on NEPOOL's 1997 CELT forecast prorated to Massachusetts (id. at 2-23 to 2-25; Exhs. HO-N-2, at 1; HO-RR-12.4; HO-RR-13.5). The Company stated that it then combined its demand and supply forecasts to produce a series of need forecasts (Exh. BEL-1, at 2-23).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including its demand forecast methods and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including its capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the Company's need analyses for Massachusetts.

(1) Demand Forecasts, DSM and Adjusted Load Forecasts

(a) Description

The Company indicated that it relied primarily on information contained in the 1997 CELT report and NEPOOL's most recent Massachusetts-specific forecast of adjusted summer peak load,[29] which was published in 1994, to develop a Massachusetts peak load forecast (id.; Exhs. HO-N-2, at 1; HO-RR-13.5). The Company explained that it prorated the 1997 CELT unadjusted reference forecast by the ratio of the 1994 NEPOOL forecast for Massachusetts to the 1994 CELT reference forecast to develop a Massachusetts unadjusted reference forecast (Exhs. BEL-1, at 2-23; HO-N-2, at 1; HO-RR-13.5). The Company indicated that it applied the same 1994 ratios to the base, high and low DSM forecast and the NUG netted from load forecast in the 1997 CELT report and subtracted the prorated DSM and NUG netted from loads from the Massachusetts unadjusted reference forecast to develop Massachusetts adjusted forecasts (Exh. HO-RR-13.5).

The Company stated that it applied the same 1994 ratios to the 1997 CELT forecast high and low load forecasts to develop Massachusetts high case and low case forecasts, respectively (Exh. BEL-1, at 2-24).

Consistent with the regional need analysis, the Company provided the 1997 Massachusetts forecast of summer peak load, combined with the three aforementioned forecasts of DSM savings to develop forecasts of adjusted load (Exh. HO-RR-13.5).

(b) Analysis

In its Massachusetts need analysis, ANP provided base case demand forecasts for summer peak load which correspond to the base case demand forecasts presented in its regional need analysis. ANP also provided high and low forecasts of summer peak load demand in Massachusetts which correspond to the high and low forecast presented in the regional need analysis. Additionally, the Company provided high and low DSM cases for

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29 ANP stated that, like the regional need, the summer peak load rather than the winter peak load drives the need for capacity (Exh. BEL-1, at 2-4; Tr. 1, at 80).

Massachusetts, which correspond to the set of assumptions used in the regional analysis.

The Siting Board reviewed the regional demand forecasts in Section II.A.2.a.(1), above. Consistent with its findings concerning the regional demand forecasts, the Siting Board finds that (1) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1997 Massachusetts forecast of summer peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need for the years 2000 and beyond.

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.(1), above. Consistent with its findings concerning the regional forecasts of DSM savings, the Siting Board finds that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

(2) Supply Forecast and Reserve Margin

(a) Description

ANP stated that it developed base, high and low supply scenarios for Massachusetts, consistent with its regional supply scenarios, with adjustments to reflect generating resource ownership and commitments of Massachusetts electric utility companies (Exh. BEL-1, at 2-24).

The Company stated that it used information in the 1997 CELT Report to determine, on a utility-by-utility basis, the capacity committed to utilities serving Massachusetts customers, including the total capability for utility generating capacity and non-utility capacity purchases claimed by utilities serving load exclusively within Massachusetts, combined with a percentage of the capability claimed by Massachusetts utilities that are part of holding companies serving load in multiple states including Massachusetts (id. at 2-24; Exh. HO-RR-

12, at 3). The Company stated that it allocated an amount of these multi-state holding-companies' capacity to Massachusetts by calculating for each such holding company the ratio of Massachusetts peak load to total peak load on each system, and then using this ratio to apportion to Massachusetts the capacity of each generating facility owned by the holding company (Exh. HO-N-17).[30]

The Company stated that its Massachusetts base, high and low case supply scenarios are comparable to the regional base, high and low case supply scenarios. In allocating the share of the projects currently under development to Massachusetts, ANP assumed that Massachusetts consumers would purchase output from these facilities in proportion to Massachusetts' share of the New England market (Exh. BEL-1, at 2-24).

The Company stated that it assumed the same yearly percentage reserve margin requirements for Massachusetts as were assumed for the region (id. at 2-19). These percentages were applied to the Massachusetts load forecasts (id.).

(b) Analysis

The Company provided a base case, low case and high case supply scenario for Massachusetts, corresponding to the supply forecasts presented in its regional need analysis. The Siting Board reviewed those forecasts in Section II.A.2.a.(2), above.

Consistent with its findings relative to the regional need analysis, the Siting Board finds that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need.

The Company assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region. Consistent with its findings relative to the

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30 The Company stated that the ratios for the Massachusetts share of multi-state utility capacity are as follows: (1) 0.734 for New England Electric System; (2) 0.608 for Eastern Utilities Associates; and (3) 0.113 for NU (Exh. HO-N-17.1).

regional need analysis, the Siting Board finds that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

(3) Need Forecasts

(a) Description

Consistent with its regional need forecasts, the Company developed nine summer need forecasts by adjusting the 1997 Massachusetts forecast by each of three DSM scenarios, and combining each of the resulting three summer adjusted demand forecasts with three supply forecasts (Exh. HO-RR-13.5, 13.6, 13.7). Of these nine summer need forecasts, all demonstrate a sustained need for at least 580 MW of capacity in 2000.[31] See Table 2, below.

Table 2

RANGE OF MASS NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1997 CELT	High	(912)	(1,172)	(1,528)
1997 CELT	Base	(991)	(1,252)	(1,607)
1997 CELT	Low	(1,071)	(1,332)	(1,687)

Source: Exh. HO-RR-13.5,13.6, 13.7
Capacity deficits are shown in parentheses.

31 Consistent with the regional need analysis, the Company also presented need analyses based on the Massachusetts high case demand forecast and Massachusetts low case demand forecast, each adjusted by the base case DSM forecast and base case supply forecast (Exh. BEL-1, app. E). The need analysis based on the Massachusetts high case demand forecast shows a need for 580 MW in 2000 while the need analysis based on the Massachusetts low case demand forecast shows a need for 580 MW in 2004 (id.; Exh. HO-RR-12.4).

(b) Analysis

Consistent with the regional need analysis, the Siting Board finds that it is appropriate to consider explicitly Massachusetts need for the proposed facility starting in 2000, the year that ANP Power is proposed to enter service.

The Siting Board has found that: (1) the Massachusetts high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand, and (2) the 1997 Massachusetts forecast of summer and winter peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need.

In considering the Company's DSM forecasts, the Siting Board has found that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need. In addition, the Siting Board has found that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

The capacity under the Massachusetts summer forecasts, based on the 1997 Massachusetts forecast, for the 2000 is shown in Table 2, above. All such summer need forecasts show a sustained need for at least 580 MW in 2000. Accordingly, the Siting Board finds that there is a sustained need for 580 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

3. Economic Need

a. New England

(1) Description

The Company asserted that there is an economic need in the region for the addition of more than 545 MW[32] of low cost, high availability, base load capacity of the type offered by the proposed facility by the year 2000, both under the existing NEPOOL dispatch system and under a modified dispatch system consistent with electric industry restructuring (Exh. BEL-1, at 2-27). ANP explained that the proposed unit would provide significant cost advantages over other existing supplies in the market due to the replacement of lost nuclear capacity and displacement of more expensive fuels from the existing stock (Tr. 1, at 126).

(a) Existing NEPOOL Dispatch

In support of its assertions, the Company provided a series of detailed economic analyses based on modeling of existing NEPOOL economic dispatch practices[33] for the 5-year period, 2000 through 2004, which compared the total incremental costs of two scenarios -- one that included the dispatch of the proposed facility ("ANP-in case") and another that lacked the proposed facility in the dispatch ("ANP-out case") (Exhs. BEL-1, at 2-28 to 2-19; HO-RR-20.1). The Company stated that these analyses demonstrate that the proposed facility

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32 ANP stated that because the proposed project will not operate with power augmentation throughout the year, the analysis conservatively assumes the base plant nominal output of 545 MW (Exh. BEL-1, at n.30). Because of the inherent difficulty in predicting the timing and duration of the additional output from steam augmentation, the Siting Board here considers the economic need for the baseload capacity only.

33 The Company stated that the current NEPOOL dispatch order is based on the variable costs (i.e., fuel costs, and variable O&M) of NEPOOL units (Tr. 1, at 110-111). The Company explained that generation costs (i.e., the fixed costs associated with must-run PURPA contracts and costs for all generation units including fixed O&M, administrative, property taxes, capital additions and return on investment) are traditionally recovered through rate base (Exh HO-RR-15). The Company noted that in a deregulated market, producers will need to cover these costs with revenues resulting from market clearing price payments (id.).

would provide significant economic efficiency benefits to the region that would be equal to the difference of the region's cost of electricity under these two scenarios (Exh. BEL-1, at 2-30).

The Company stated that it used the ENPRO model to simulate NEPOOL's dispatch on an hourly basis over the forecast period (id. at 2-28). The Company stated that inputs into the model included: (1) generation supply identical to the base case supply scenario;[34] (2) load growth identical to the base peak load forecast; (3) the actual 1994 load duration curve; (4) operating and cost characteristics of individual generating facilities;[35] (5) classification of specific units as must-run;[36](6) addition of new generic capacity to meet projected regional capacity requirements; (7) fuel price forecasts;[37] and (8) operating characteristics of the proposed facility[38] (id. at 2-28 to 2-30; Exhs. HO-RR-13.2;

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34 ANP noted that, in the dispatch analysis, the Hydro-Quebec contract is assumed to continue to supply 85 percent of the energy it currently delivers under the Phase II contract after that contract expires in 2000 (Exh. BEL-1, at 2-19). ANP further noted that the capacity credit associated with the tie line to Hydro-Quebec was incorporated into the reliability need analysis by reducing the reserve margin requirement (id.).

35 The Company stated that data on capacity, heat rates, fuel types, O&M costs, and availability rates was obtained for each generating unit from a number of sources including the 1996 CELT report, the 1995 FERC Form 1 Reports for various New England utilities and the 1995 NEPOOL Generation Task Force ("GTF") Report (Exh. HO-N-21). The Company assumed that dual-fuel units would run eight months on natural gas and four months on oil (Exh. HO-RR-20.1).

36 The Company indicated that all nuclear units were classified as must-run due to their inability to cycle efficiently (Exh. HO-N-22). The Company indicated that most NUG generation units also were classified as must-run because, due to their contracts, they are not dispatchable by NEPOOL (id.). The Company noted that the must-run status for all units is identical for all dispatch analyses (id.).

37 ANP stated that fuel cost assumptions were obtained from the U.S. Energy Information Administration's Annual Energy Outlook for 1997 and were updated to incorporate monthly variation in oil and natural gas prices, variable natural gas costs and pipeline losses (Exhs. BEL-1, at n.36; HO-RR-20.1).

38 ANP stated that the proposed facility was assumed to operate without steam augmentation at 545 MW with an average availability of 92 percent (Exh. BEL-1, at
(continued...)

HO-RR-20.1). The Company noted that SO_2 allowance costs were explicitly incorporated into the economic dispatch (Exh. HO-RR-20.1).

The Company calculated energy efficiency savings for the years 2000 through 2004 based on meeting projected regional capacity requirements with generic combustion turbine ("CT") units ("CT scenario") (Exh HO-RR-20.5).[39] The Company maintained that the CT scenario demonstrates the economic need for baseload capacity as opposed to peaking capacity (Exh. HO-N-19). However, the Company noted that an economically optimized expansion plan likely would include the addition of more baseload combined cycle ("CC") capacity than the capacity of the proposed facility (id.). In response to the Siting Board Staff, the Company also calculated energy efficiency savings based on meeting projected regional capacity requirements with generic CC units ("CC scenario") (Exh. HO-RR-20.5).[40] ANP noted that its analysis assumes the same cost and performance characteristics for the generic CC capacity additions and the proposed facility (Exh. HO-RR-20.1).

The Company indicated that the model provided the NEPOOL system variable costs, new capacity fixed costs, and proposed facility costs associated with each set of assumptions (Exh. BEL-1, at 2-30 and app. G). The Company stated that the NEPOOL system-wide savings attributable to the proposed facility would be the difference in total costs between the

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[38](...continued)
2-29 to 2-30). ANP also stated that costs were based on the pro forma and that the gas supply was assumed to be a 365-day firm supply (id. at 2-30). The Company stated that this set of performance, cost and fuel supply assumptions results in a conservative assessment of the economic need for baseload capacity relative to the attributes of the proposed project (id.).

[39] To meet capacity need in the CT scenario, the Company added in each year of the forecast: (1) CT capacity as required (1,567 MW in 2000 increasing to 2,814 MW in 2004) to meet need in the ANP-out case, and (2) 545 MW of CC capacity with the remainder CT capacity (1022 MW in 2000 increasing to 2269 MW in 2004) in the ANP-in case (Exh. HO-RR-20.2).

[40] To meet capacity need in the CC scenario, the Company added, in each year of the forecast period, (1) CT capacity totalling 545 MW and CC capacity as required (1,022 MW in 2000 increasing to 2,269 MW in 2004) in the ANP-out case, and (2) CC capacity as required (1,567 MW in 2000 increasing to 2,814 MW in 2004) in the ANP-in case (Exh. HO-RR-20.2).

ANP-in case and ANP-out case (id. at 2-28 to 2-29). The Company stated that the annual nominal savings over the 2000 to 2004 period were discounted to mid-year 2000 to obtain the net present value ("NPV") of economic efficiency savings attributable to the proposed project (Exh. HO-RR-14).

The Company indicated that under the existing NEPOOL dispatch practices and the CC scenario, the proposed project would result in savings with a NPV of $17 million in year 2000 dollars[41] over the five-year forecast period (Exh. HO-RR-20.5). The Company indicated that the annual cost savings would be $2.6 million in 2000, $4.2 in 2001, $6.1 million in 2002, $4.4 million in 2003, and $4.0 million in 2004 (id.).[42]

(b) Dispatch Under Deregulated Generation Market

ANP asserted that the proposed project would provide regional energy efficiency benefits under deregulation because introduction of the proposed project into the market would cause the market clearing price of energy to decline, leading to a reduction in the total payment for energy for the region (Exh. BEL-1, at 2-33, 2-38). The Company stated that in a deregulated market, suppliers will offer power to the market for a bid price and the Independent System Operator will purchase power from the suppliers in order of bid prices, starting with the lowest bids, up to the need for each hour (id. at 2-38; Tr. 1, at 100-101). The Company also stated that all suppliers will be paid the market clearing price -- the bid price of the most expensive unit dispatched in each hour (Tr. 1, at 99-101). The Company explained that the total energy revenues would equal the market clearing price multiplied by the energy demand in the region (Exh. BEL-1, at 2-38).

The Company provided a series of detailed economic analyses based on modeling regional dispatch under a deregulated generation market for the five-year period 2000 through 2004 which compared the total payment for energy for the ANP-in and ANP-out cases (id.;

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41 All NPV savings figures referenced in this analysis are expressed in year 2000 dollars.

42 ANP indicated that cost savings over the five-year period under the CT scenario would have a NPV of $95 million, significantly more than the cost savings under the CC scenario (Exh. HO-RR-20.5).

Exh. HO-RR-20). Consistent with the existing NEPOOL dispatch analysis, the Company estimated total payment for energy based on two different scenarios of generic capacity additions to meet the projected regional capacity requirements -- the CT scenario, and the CC scenario (Exh. HO-RR-20).[43]

The Company indicated that savings would be greater under the deregulated generation market dispatch than under the NEPOOL dispatch (Exh. HO-RR-20.5, 20.5B). The Company indicated that under the deregulated generation market and the CC scenario, the proposed project would result in savings with a NPV of $583 million over the five-year forecast period (Exh. HO-RR-20.5B).[44] The Company indicated that the annual cost savings would be $127.5 million in 2000, $129.0 in 2001, $141.5 million in 2002, $153.2 million in 2003, and $158.6 million in 2004 (id.).[45]

(2) Analysis

In the past, the Siting Board has determined that, in some instances, utilities need to add energy resources primarily for economic efficiency purposes. Specifically, in the 1985 MECo/NEPCo Decision, 13 DOMSC at 178-179, 183, 187, 246-247, and in Boston Gas Company, 11 DOMSC 159, 166-168 (1984), the Siting Board recognized the benefit of adding economic supplies to a specific utility system. In addition, where a non-utility developer has proposed a generating facility for a number of power purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, the Siting

43 The Company indicated that the assumptions, including capacity additions, input into the deregulated dispatch model were consistent with the assumptions input into the NEPOOL dispatch model (Exhs. BEL-1, at 2-39; HO-RR-20).

44 Mr. Peaco noted that this analysis shows that the introduction of one more unit like the proposed facility to the existing generation mix would bring significant downward pressure on the market resulting in economic savings for the market (Tr. 1, at 123). He added that with successive additional entrants to the market, the incremental savings would decrease (id. at 121-122).

45 As in the NEPOOL dispatch analysis, the Company indicated that the NPV of savings under the CT scenario -- $807 million over the five year period -- would be greater than the savings under the CC scenario (Exh. HO-RR-20.5B).

Board standard indicates that need may be established on either reliability, economic, or environmental grounds. Millennium Power Decision, Berkshire Power Decision, 4 DOMSB at 292-93; NEA Decision, 16 DOMSC at 344-360.

In previous reviews of non-utility proposals to construct electric generation projects, project proponents have argued that additional energy resources were needed in the region based on economic efficiency grounds, i.e., that the construction and operation of a particular project would result in a significant reduction in total cost of generating power in the New England region through the displacement of more expensive sources of power. Millennium Power Decision, Berkshire Power Decision, 4 DOMSB at 285-292; MASSPOWER Decision, 20 DOMSC at 19.

In some cases, the Siting Board rejected companies' arguments, finding problems with elements of their analyses. In those decisions the Siting Board noted that proponents must provide adequate analyses and documentation in support of assertions that their respective projects are needed on economic efficiency grounds. See Eastern Energy Corporation, 22 DOMSC 188, 210-211 (1991) ("EEC Decision"); West Lynn Decision, 22 DOMSC at 14; MASSPOWER Decision, 20 DOMSC at 19.

In more recent reviews of non-utility proposals, the Siting Board has found that the proposed projects were needed for economic efficiency purposes. Millennium Power Decision, EFSB 96-4, at 40; Berkshire Power Decision, 4 DOMSB at 295-96; Enron Decision, 23 DOMSC at 55-62. The Siting Board has noted that such findings, based on a comprehensive analysis of NEPOOL dispatch, both with and without each proposed project, are necessarily project-specific. The Siting Board also has identified the magnitude and timing of such gains as critical to its review. See Berkshire Power Decision, 4 DOMSB at 293.

Here, the Company has provided a five-year analysis of economic efficiency savings with a detailed description of its methods and assumptions under two different dispatch scenarios and two different generation expansion scenarios. The Company states that the CT scenario demonstrates the economic need for baseload capacity as opposed to peaking capacity but noted that an economically optimized expansion plan likely would include new baseload CC capacity in addition to the proposed facility. Here, the Siting Board focuses on the CC scenario, the more realistic of the two scenarios.

In developing the CC scenario, the Company assumed the same efficiency for the generic CC units and proposed project. In previous cases the Siting Board has expressed concern over companies' assumption of efficiency advantages for their projects relative to generic units and the lack of efficiency improvements for generic units, particularly in the long term. See Millennium Power Decision, EFSB 96-4, at 40-41. Here, although the Company does not assume any efficiency improvements for later generic units, its assumption of equal efficiency is reasonable, given the short five-year time frame of the analysis.

The analyses provided by the Company indicate that under both dispatch scenarios, the proposed project would provide substantial economic efficiency savings over the five-year period from 2000 to 2004, ranging from $17 million in year 2000 dollars under the existing NEPOOL dispatch scenario to $583 million in year 2000 dollars under the deregulated generation market dispatch scenario.

Accordingly, the Siting Board finds that the Company has established that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

b. Massachusetts

(1) Description

To demonstrate Massachusetts economic efficiency benefits, the Company allocated a pro rata share of the regional economic efficiency benefits to Massachusetts based on the ratio of Massachusetts energy requirements to NEPOOL energy requirements (Exhs. HO-RR-16; HO-RR-20).[46]

Assuming existing NEPOOL dispatch and the CC scenario, the Company estimated that the proposed project would result in savings with a NPV of $8 million in Massachusetts over the five year forecast period (Exh. HO-RR-20.5). The Company indicated that the

46 The Company indicated that this methodology was consistent with the method used to determine Massachusetts need for reliability purposes (Exh. BEL-1, at 2-32).

annual cost savings for Massachusetts would be $1.2 million in 2000, $2.0 million in 2001, $2.8 million in 2002, $2.0 million in 2003, and $1.9 million in 2004 (id.).

Assuming deregulated generation market dispatch and the CC scenario, the Company estimated that the proposed project would result in savings with a NPV of $272 million in Massachusetts over the five year forecast period (Exh. HO-RR-20.5B). The Company indicated that the annual cost savings for Massachusetts would be $59.2 million in 2000, $60.3 million in 2001, $65.8 million in 2002, $71.1 million in 2003, and $73.5 million in 2004 (id.).

(2) Analysis

In Section, II.A.3.a., above, the Siting Board found that there would be a need in New England for 545 MW of additional energy resources from the proposed project for economic efficiency purposes beginning in 2000. In addition, the Company provided analyses that estimated the extent of savings that would accrue to Massachusetts -- savings due to the operation of the proposed facility that would be $8 million under existing NEPOOL dispatch and $272 million under a deregulated generation market dispatch, discounted to year 2000 dollars, over the 2000 to 2004 time period.

Accordingly, the Siting Board finds that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

4. Environmental Need

a. New England

(1) Description

The Company asserted that the operation of the proposed facility would provide the region with substantial net benefits in the form of reduced system-wide emissions of pollutants, due to the proposed facility's displacement of generating facilities that are less efficient and have higher air pollutant emission rates (Exh. BEL-1, at 2-41). In support, the Company presented dispatch analyses based on existing NEPOOL dispatch practices, which compare the total system-wide emissions of sulfur dioxide ("SO_2"), NOx and carbon dioxide

("CO_2") under two scenarios -- the ANP-in case and the ANP-out case (id. at 2-41 to 2-42; HO-RR-20.9, 20-10). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exh. HO-RR-20.9, 20.10).

ANP indicated that it used the ENPRO model with assumptions consistent with the economic dispatch analysis and plant-specific emissions data to determine regional emissions for each pollutant in tons per year ("tpy") (Exh. BEL-1, at 2-41 to 2-42). The Company stated that emission rates for: (1) the proposed facility and generic CCs were based on plant-specific data for the proposed facility; (2) all existing utility units larger than 25 MW were based on 1996 actual data from the EPA's Continuous Emissions Monitoring System ("CEMS"); (3) existing NUG units, not included in CEMS, were based on the emission rates for the NEP Manchester Street CC facility; (4) existing peaking units were based on 1995 GTF report assumptions for SO_2 and NOx and on emission rates for the Cleary 9 unit for CO_2; and (5) generic CTs were based on 0.3 percent sulfur oil, EPRI TAG NOx assumptions and on emission rates for the Cleary 9 unit for CO_2 (Exhs. BEL-1, at 2-42; HO-RR-17; HO-RR-20). The Company noted that the emissions rates for existing units were based on historical data and therefore did not reflect any reductions that may be required as a result of Phase II of the CAAA (Exh. HO-N-20).[47] However, as noted above, the Company incorporated SO_2 allowance costs into the analysis (Exh. HO-RR-20.1). The emissions analysis assumes constant emission rates and oil/gas mix for dual fuel units over the five-year forecast period (Exhs. HO-N-29(conf.); HO-RR-20.1).

The Company's analysis indicated that, under the CC scenario, emissions of SO_2, NOx and CO_2 would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.10). Specifically, the Company's analysis indicated reductions over the five years of: (1) 76,773 tons of SO_2, or 9.4 percent of regional emissions; (2) 20,462 tons of NOx, or 8.1 percent of regional emissions; and

[47] The Company noted that emissions requirements under Phase II of the CAAA of 1990 are in the process of being finalized throughout the Northeast and that therefore it is not clear what the requirements will be and how they will affect incremental emissions at generating facilities in New England (Exh. HO-N-30).

(3) 7.0 million tons of CO_2, or 3.2 percent of regional emissions (id.).[48]

The Company also compared the emission reductions attributable to the ANP project, as developed in its displacement analysis for the CC scenario, to the emissions impacts of the proposed facility (Exh. HO-N-25.2). This comparison shows that the five-year emissions reductions for SO_2, 76,773 tons, would be significantly larger than the proposed facility's SO_2 emissions of 242 tons over the same period (Exh. HO-N-25.2). Similarly, the five-year emissions reductions for NOx, 20,462 tons, would be significantly larger than the proposed facility's NOx emissions of 953 tons over the same period (id.). With respect to CO_2, the Company's analyses show that five-year emissions reductions, 7.0 million tons, would be 85 percent of the proposed facility's CO_2 emissions of 8.3 million tons over the same period (id.).

(2) Analysis

The Siting Board has held that a project proponent must provide full documentation of its assumptions pertaining to environmental benefits associated with the dispatch of generation capacity. Millennium Power Decision, EFSB 96-4, at 46; Berkshire Power Decision, 4 DOMSB at 300; Altresco Lynn Decision, 2 DOMSB at 99. See also, Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

In the Enron Decision, the Siting Board found for the first time that a proposed generating project would provide Massachusetts with environmental benefits related to net changes in air emissions from existing and future generating facilities in Massachusetts. 23 DOMSC at 69-73. In more recent decisions, the Siting Board has found that applicants' projects likely would provide short-term air quality benefits for Massachusetts based on the initial displacement of existing generation and associated emissions. Cabot Decision,

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48 ANP's analysis indicated that, under the CT scenario, emissions of SO_2, NOx and CO_2 also would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.9). Specifically, the Company's analysis indicated reductions over the five years of: (1) 82,934 tons of SO_2, or 7.7 percent of regional emissions; (2) 22,723 tons of NOx, or 7.0 percent of regional emissions; and (3) 8.5 million tons of CO_2, or 3.5 percent of regional emissions (id.).

2 DOMSC at 329; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings with those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly dispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million Btu ("lbs/MMBtu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. Cabot Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333. In a more recent review of a gas-fire combined-cycle ("GTCC") facility, the Siting Board raised concerns regarding assumed characteristics of future generic GTCC units in the dispatch analysis, including assumed efficiency and size relative to the proposed project.[49] Millennium Power Decision, EFSB 96-4, at 46; Berkshire Power Decision, 4 DOMSB at 302.

The Siting Board recognized in those reviews that load growth represents a given for purposes of the Company's dispatch analysis, and that the analysis must assume dispatch of available capacity to meet load growth over time. Millennium Power Decision, EFSB 96-4, at 47; Cabot Decision, 2 DOMSB at 327; EEC (remand) Decision, 1 DOMSB at 333. In the EEC (remand) Decision, the Siting Board further recognized that, to the extent that the applicant's project would in whole or in part replace existing generation that potentially will be retired, there would be significant potential for that project to provide long-term benefits through displacement of such generation. 1 DOMSB at 333.

Here, the Company has provided a comprehensive five-year analysis of dispatch effects on regional emissions for the period from 2000 through 2004. The Company's analysis includes sufficient documentation regarding the methods and assumptions used in its calculations for the Siting Board to evaluate whether there would be significant dispatch-related emissions reductions specific to the operation of the proposed project.

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49 The Siting Board noted that an analysis of air quality benefits works best for the period of time when there is no capacity need and thus no reason to speculate about the attributes of plants that will be constructed in the future. Millennium Decision, EFSB 96-4, at n.55; Berkshire Power Decision, 4 DOMSB at 302.

The Company's analytical methods are similar to those used in past Siting Board reviews of generating facilities, although the time frame and some other elements of the analysis are different. Responding to concerns in past Siting Board reviews, the Company has focused its displacement analysis on the short run and also has assumed the same efficiency for generic CC units and the proposed project. In addition, the Company's base supply case assumes retirement of 25 percent of aging fossil fuel steam units over the forecast period. This assumed retirement rate responds to concerns the Siting Board has identified in past reviews with respect to (1) assumed redispatch of displaced generation over time with continued load growth and (2) failure to address the potential for significant amounts of retirement of existing generating units.

The record also shows, however, that the displacement analysis covers a period in which significant amounts of new capacity are needed to offset load growth and earlier than expected losses of nuclear capacity; such needs potentially reduce the shares of new generation that would be available to permanently displace existing fossil fuel generating capacity. Further, the Company's displacement analysis does not explicitly identify and analyze displacement scenarios based on differential amounts of retirement of fossil fuel generation.[50] Thus it is unclear that the overall trends in generation mix reflected in the Company's analyses would necessarily demonstrate significant progress in meeting environmental goals.[51]

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50 ANP's displacement analysis assumes the same retirement increment in both the ANP-in and ANP-out cases. Therefore, the displacement benefits of ANP being on-line does not reflect such retirements, but rather is based on displacement of the new combustion turbine units assumed in the ANP-out case but not the ANP-in case. The Siting Board notes that if ANP had included additional or earlier retirements of aging fossil fuel steam units as part of its ANP-in case, it might have shown greater displacement benefits than those demonstrated in the submitted analysis based solely on displacement of new combustion turbine units.

51 We note that for several regional or worldwide air quality concerns, including ozone, acid rain and climate change, statutory or other policy goals point to a need to avoid or substantially minimize regional or national emissions increases. The pollutants that relate to such concerns include SO_2, NOx and CO_2. See Millennium Decision, EFSB 96-4, at 49; Berkshire Power Decision, 4 DOMSB at 302.

At the same time, the Siting Board notes that the Company was able to demonstrate, through its displacement analysis, net reductions in five-year regional SO_2 and NOx emissions inclusive of the proposed facility's emissions that significantly exceed the proposed facility's SO_2 and NOx emissions over the same period. The Company's displacement analysis shows regional CO_2 emissions net reductions which are 85 percent of the proposed facility's CO_2 emissions.

The Company has established that operation of the proposed project would result in reductions in regional emissions of NOx, SO_2, and CO_2, including reductions in emissions of SO_2 and NOx that exceed the proposed facility's own emissions. Accordingly, the Siting Board finds that, on balance, the Company has established that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

b. Massachusetts

(1) Description

To demonstrate environmental need for Massachusetts, ANP provided a dispatch analysis based on existing NEPOOL dispatch practices, which compares the emissions of SO_2, CO_2 and NOx from generating units physically located in Massachusetts under two scenarios -- the ANP-in case and the ANP-out case (Exhs. HO-RR-19; HO-RR-2012, 20-13). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exh. HO-RR-20.12, 20.13).[52]

The Company's analysis indicated that, under the CC scenario, emissions of SO_2, NOx and CO_2 would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.10). Specifically, the Company's analysis indicated reductions over the five years of: (1) 42,794 tons of SO_2, or 9.5 percent of

52 ANP noted that the transport of emissions across state lines makes it difficult to define state-specific improvements in air quality as a result of reductions from specific units and that overall reductions in regional pollutant emissions have benefits for each state in the region (Exh. BEL-1, at 2-44).

Massachusetts emissions; (2) 10,913 tons of NOx, or 7.9 percent of Massachusetts emissions; and (3) 587,264 tons of CO_2, or 0.5 percent of Massachusetts emissions (id.).[53]

(2) Analysis

The Siting Board recognizes the complexity in estimating pollutant emissions for Massachusetts due to the transportation of pollutants across state lines and the uncertainty regarding the location of facilities to be developed in the future. The Company's approach for estimating Massachusetts emissions benefits by including all generating units physically located in Massachusetts is reasonable. The Company's analysis demonstrates emissions reductions in Massachusetts for SO_2, NOx and CO_2 over the five-year analysis period.

Accordingly, the Siting Board finds that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

5. Conclusions on Need

The Siting Board has found that there will be a sustained need for 580 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2000. In addition, the Siting Board has found that there will be a sustained need for 580 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2000.

The Siting Board also has found that, consistent with its findings regarding reliability need in New England, there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004. In addition, the Siting Board has found that there

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53 ANP's analysis indicated that, under the CT scenario, emissions of SO_2, NOx and CO_2 also would be reduced in the ANP-in case, compared to the ANP-out case, over the five-year period from 2000 through 2004 (Exh. HO-RR-20.12). Specifically, the Company's analysis indicated reductions over the five years of: (1) 42,103 tons of SO_2, or 7.2 percent of Massachusetts emissions; (2) 10,787 tons of NOx, or 6.3 percent of Massachusetts emissions; and (3) 173,531 tons of CO_2, or 0.1 percent of Massachusetts emissions (id.).

will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for economic efficiency purposes in the years 2000 through 2004.

Further, the Siting Board has found that there will be a need in New England for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004. In addition, the Siting Board has found that there will be a need in Massachusetts for the additional energy resources produced by the baseload operation of the proposed project for environmental purposes in the years 2000 through 2004.

Based on a showing of a sustained need for 580 MW or more of additional energy resources in the Commonwealth for reliability purposes, combined with a need for the additional energy resources provided by the baseload operation of the proposed project for both economic and environmental purposes in the years 2000 through 2004, the Siting Board finds that the proposed project is needed to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, beginning in the year 2000.

B. Alternative Technologies Comparison

1. Standard of Review

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

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need in terms of cost, environmental impact and reliability.

Millennium Power Decision, EFSB 96-4, at 51 to 52; Berkshire Power Decision, 4 DOMSB at 304; Cabot Decision, 2 DOMSB at 334.

2. Identification of Resource Alternatives

a. Description

To address the identified need for additional energy resources, the Company proposes to construct a nominal net 580-MW gas-fired, combined-cycle facility in Bellingham, Massachusetts, which would commence commercial operation in the second quarter of the year 2000 (Exh. BEL-1, at 1-1 to 1-2). The Company indicated that the proposed project would operate with an approximate heat rate of 6700 Btu/KWh and an availability factor of 92 percent (id. at 3-21).

The Company stated that it used a three-phase screening process to examine all reasonable alternative technologies (Exh. BEL-1, at 3-2). The Company stated that, as a first step, it compiled a list of electric generating technologies capable of operating, like the proposed project, in baseload or intermediate mode, and then subjected each technology to a fatal flaw analysis, i.e., it evaluated each technology for siting/permitting feasibility, maturity, cost effectiveness, and suitability under regional policy guidelines (id. at 3-3 to 3-4). The Company indicated that, in selecting technologies for further evaluation in phase two, it conservatively included technologies which appeared to be at least marginally viable in terms of meeting the identified need (id. at 3-4). The phase one evaluation resulted in a list of nine potentially viable technologies: (1) gas-fired combined cycle ("GCC"); (2) coal-fired atmospheric fluidized bed ("AFB"); (3) coal-fired pressurized fluidized bed ("PFB"); (4) integrated coal gasification ("CG"); (5) pulverized coal ("PC"); (6) wind energy; (7) municipal solid waste; (8) biomass; and (9) fuel cells (id. at 3-3 to 3-4).

The Company stated that it initially based its phase one review and fatal flaw analysis on the latest publicly available copies of two documents, the EPRI Technical Assessment Guide: Electricity Supply - 1993, EPRI TR-102275-V1R7 ("TAG"), and the 1995 NEPOOL Summary of Generation Task Force Long-Range Study Assumptions ("GTF Report") (id.). The Company also identified sources more current than the 1993 TAG and the 1995 GTF Report for information on technology alternatives in response to the Siting Board's directive, established in its Millennium Power Decision, EFSB 96-4 at 55, n.61, that future project proponents use current TAG data or pursue alternative sources (Exh. HO-A-11).[54] The Company submitted cost and performance assumptions from its alternative sources which were within the range of estimates from the 1993 TAG (Exh. HO-A-11.1).

The Company stated that, because it did not have access to the most recent TAG data, it investigated alternative sources of information, including information available from the Department of Energy ("DOE") and affiliated organizations, as well as other publicly available information on the AFB, PFB, CG, PC and wind energy alternatives (Exh. HO-A-11S). The Company provided a summary of the results of its research, including a description of the 1993 TAG analysis of each of the considered technologies, a description of new projects identified, a summary of any recent technological improvements, and the Company's assessment of any updates to the 1993 TAG data indicated as a result of its research (id.; Exh. HO-A-11.1). At the request of the Siting Board, the Company also provided a range of recent (published 1997) cost and performance data for technology alternatives eliminated in phase one, including solar energy (Exhs. HO-RR-22, HO-RR-22.1, HO-RR-23.2(red.)). In addition, the Company provided information in support of its view that distributed generation of such technology alternatives as diesel engines, combustion turbines, fuel cells, wind power and photovoltaic cells would not be a practical alternative to the proposed project because of potential permitting difficulties, lack of technical maturity, and inadequate availability of power (Exhs. HO-A-10; HO-RR-21; HO-RR-21.1; HO-RR-22; HO-RR-22.1).

The Company stated that phase two of its analysis involved narrowing the group of nine potential technologies identified in phase one to a group of reasonably practical alternatives based on the following five criteria: technical maturity; siting/permitting

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[54] The Company indicated that due to the increasing competitiveness of the power industry, the latest update of the TAG is available only to those EPRI members who provided financial support toward its compilation (Exh. HO-A-11). The Company explained that the 1993 TAG is the last report available without membership in EPRI and the EPRI TAG group (id.). The Company stated that the cost of joining EPRI and the EPRI TAG group was on the order of $75,000 to $100,000 for each membership (Tr. 2, at 52 to 54).

feasibility; reliability; cost-effectiveness; and ability to meet the identified need at a single site (Exh. BEL-1, at 3-9). The Company stated that while its phase two criteria were similar to its phase one criteria, phase two criteria were distinguished by tighter thresholds (id.). Those technologies failing to meet the standard for two or more phase two criteria were eliminated from further review (id.).

Based on its phase two analysis, the Company concluded that the wind energy, municipal solid waste, biomass and fuel cell technologies were not reasonably practical alternatives for the following reasons:

Technology Eliminated	Rationale
Wind Energy	Rated "demonstration" (rather than "mature" or "commercial" by Tag Report); reliability constraints due to intermittent nature of resource; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct wind energy facilities capable of producing 545 MW
Municipal Solid Waste	Permitting constraints due to emissions and fact that MA has reached 50 percent limit for power generation from combustible waste established by state policy; relatively higher cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct municipal solid waste facilities capable of producing 545 MW
Biomass	High cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct biomass facilities capable of producing 545 MW
Fuel Cells	Rated "demonstration" (rather than "mature" or "commercial" by Tag Report); relatively higher cost/kWh; multiple sites, with associated increase in environmental impacts and permitting issues, required to construct fuel cells capable of producing 545 MW

(id. at 3-6 to 3-9).

The Company therefore narrowed its list of potential technology alternatives for the proposed project to the GCC, AFB, PFB, CG and PC technologies (id. at 3-9 to 3-14). Thus, in addition to the proposed project, five technology alternatives advanced to the third phase of the Company's technology alternatives analysis (id. at 3-14). The Company indicated that the third phase of its analysis compared the environmental impacts and costs of the technology alternatives to those of the proposed project (id.).

b. Analysis

The record demonstrates that the Company narrowed the number of potential alternative technologies in two stages, to nine and then to five. In the first stage, the Company appropriately reviewed a wide range of potential generation and storage technologies and, based on reasonable criteria, narrowed its review to include nine technologies encompassing a range of technology types and fuels. In the second stage, the Company reviewed these nine technologies and eliminated technologies failing to meet two or more of the Company's stated criteria. The record demonstrates that the Company used standard industry procedures to scale each evaluated technology alternative to the size of the proposed project, and appropriately analyzed the possibility of using distributed generation to supply the identified need for energy.

Thus the record demonstrates that all technologies have been evaluated based on the same output and criteria. The Siting Board finds that the proposed project, the GCC and the coal-fired AFB, PFB, CG and PC alternatives are comparable in terms of their ability to meet the identified need. Because the record demonstrates that the GCC technology alternative is in no respect superior to the proposed project, the Siting Board will not review it further.[55] Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Board compares the proposed project to each of four technology alternatives: AFB, PFB, CG and PC.

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55 The GCC technology alternative is omitted from further review in keeping with the principle established by the Siting Board in Millennium Power Decision that the Siting Board would review a generic version of the proposed technology only in the event of the generic unit's superiority to the proposed project in some respect (EFSB 96-4, at 54, n.59).

3. Environmental Impacts

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

The Company stated that, to the extent possible, the alternative technologies and the proposed project were compared based on the same level of net electric output, 545 MW, and assumed to begin commercial operation at the same time, in the second quarter of the year 2000 (Exh. BEL-1, at 1-1 to 1-2, 3-2).[56]

In addition, the Company indicated that: (1) the AFB generator operates at a full load heat rate of 9,796 Btu/kWh and has an equivalent availability of 90.4 percent; (2) the PFB generator operates at a full load heat rate of 8,959 Btu/kWh and has an equivalent availability of 80.8 percent; (3) the CG generator operates at a full load heat rate of 8,090 Btu/kWh and has an equivalent availability of 85.7 percent; and (4) the PC unit operates at 9,618 Btu/kWh and has an equivalent availability of 85.5 percent (id. at 3-21). The Company noted that the proposed project offers a higher projected availability factor, 92 percent, and lower heat rate, 6,700 Btu/kWh, than any of the alternative technologies (Exh. BEL-1, at 3-21; see Table 4, Section II.B.4.a, below).

The Company indicated that it gathered the bulk of its cost and performance data for the technology alternatives from vendors for the proposed project and from the 1993 TAG (Exh. BEL-1, at 3-12; Tr. 2, at 93 to 95).[57]

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56 The Company stated that impacts of the proposed project were calculated to reflect the additional output potential associated with steam augmentation, i.e., a total nominal output of 580 MW.

57 The Company stated that it used the DOE 1997 Annual Energy Outlook as the source document for developing fuel prices (Tr. 2, at 95). The Company stated that its intent was to estimate, for each technology, a year-2000 delivered fuel price for the New England region (id. at 95 to 96).

a. Air Quality

The Company asserted that the proposed project would be preferable to the four alternative technologies with respect to air quality (Exh. BEL-1, at 3-15). In support of its assertion, the Company provided an analysis of the average annual emission rates and the total annual emissions of SO_2, NOx, PM-10, CO, VOCs and CO_2 for the proposed project and the technology alternatives (id. at 3-24). For the proposed project, the Company stated that emissions reflect power augmentation throughout the year, but that generation output was based on the base 545 MW annual average (id. at 3-15). The Company stated that emissions for the coal alternatives were calculated based on data from various sources, including the EPA's RACT/BACT/LAER clearinghouse and the 1995 GTF Report, and are considered to represent RACT, BACT and LAER technologies (id.).

The Company stated that the proposed project would produce lower annual emissions of SO_2, NOx, CO and CO_2 than each of the evaluated alternatives (id. at 3-15, 3-24). The Company originally indicated that emissions of PM-10 and VOCs from the proposed project would be the same as or slightly higher than the same emissions from the AFB, PFB and CG alternatives. However, the Company subsequently submitted revised VOCs emission figures from its turbine vendor which indicated that VOCs emissions would be reduced to 33 tons/year (.0032 lbs/MMBTU), a level considerably lower than any of the evaluated alternatives (Exhs. BEL-13.2; BEL-1, at 3-24; Company Brief at 53). See Table 3, below.

Table 3
Alternative Technologies - Pollutant Emissions

	ANP-Bellingham*	AFB	PFB	CG	PC
Ann. average emission rates (lbs/MMBTU)					
SO_2	0.0055	0.21	0.129	0.078	0.16
NOx	0.0127	0.10	0.10	0.035	0.17
PM-10	0.0138	0.015	0.018	0.013	0.018
CO	0.0055	0.13	0.18	0.056	0.10
VOC	0.0032	0.005	0.004	0.007	0.0036
CO_2	112	204	204	204	204
Ann. emissions (tpy), based on assumed availability factor					
Availability Factor	92%	90.4%	80.8%	85.7%	85.5%
SO_2	82	4439	2229	1291	3128
NOx	186	2114	1728	579	3324
PM-10	203	317	311	215	352
CO	82	2748	311	927	1955
VOC	33	106	69	116	70
CO_2 (1,000 tpy)	1,648	4,312	3,525	3,376	3,989

Source: Exhs. BEL-1, at 3-24; BEL-13.2, App. B.

* Emissions for ANP-Bellingham, with the exception of VOCs, are initial estimates. Actual emissions for some pollutants are likely to be lower as a result of on-going refinement of the proposed project.

The record demonstrates that, considering all pollutants, the annual emissions of the proposed project would be lower than those of the four technology alternatives. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to air quality.

b. Water Supply and Wastewater

The Company asserted that each of the coal-fired alternatives would require a significantly greater water supply and would generate significantly greater amounts of wastewater than the proposed project (Exh. BEL-1, at 3-15 to 3-16).

The Company indicated that the proposed project, which incorporates dry mechanical cooling, will not require cooling water, but will require water volumes for steam augmentation purposes above and beyond base-load water requirements. The Company indicated that base-load water supply needs for the proposed facility, including potable water supply, would be approximately 14,000 gallons per day ("gpd") (Exh. BCC(2)-WW4.1; Tr. 10, at 129). The Company indicated that, with the likely maximum use of steam augmentation, total average daily water use for the proposed project would be 179,000 gpd based on 302.2 days of operation per year (Tr. 11, at 52).[58]

The Company stated that the amount of water necessary for the coal-fired technology alternatives is a function of the size of the steam turbine and coal handling/processing requirements (Exh. BEL-1, at 3-16). With respect to water supply needs, assuming dry mechanical cooling and a steam turbine in all cases, the Company stated that the AFB alternative would require 3,787,705 gpd based on use of a 545 MW turbine; the PFB alternative, with a 436 MW turbine, would require 3,030,164 gpd; the CG alternative would use a 202 MW turbine and require 1,403,954 gpd; and the PC alternative, with a 545 MW turbine, would require 3,787,705 gpd (id. at 3-16, 3-25).

58 The Company indicated that it was unlikely to exceed this maximum because the additional expense of purchasing more water at higher rates from the Town would be financially disadvantageous to the proposed project (Tr. 10, at 71 to 72) (see Section III.B.2.b, below).

The Company indicated that, with the exception of occasional periods of special maintenance activity, the maximum process wastewater discharges for the proposed project would be approximately 8,000 gpd (Exhs. BEL-15, at 12-5; NEA-13). The Company stated that steam augmentation would not increase these volumes (Tr. 11, at 138). The Company indicated that process wastewater would be significantly higher for the considered technology alternatives, with the exception of the PC alternative which is assumed to have no process wastewater discharge due to its use of wastewater for scrubber makeup water (Exh. BEL-1, at 3-16, 3-25). The Company indicated that process wastewater for the AFB, PFB and CG alternatives would be 427,395 gpd, 341,916 gpd and 698,718 gpd, respectively (id. at 3-25).

The record demonstrates that the water supply requirements of the proposed project would be approximately 13 percent of the water supply requirements of the CG alternative, and approximately five percent of the water supply requirements of each of the AFB, PFB and PC alternatives. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to water use.

The record further demonstrates that the wastewater generated by the proposed project would be two percent of the wastewater generated by the AFB and PFB alternatives, and one percent of the wastewater generated by the CG alternative, but would be greater than the wastewater generated by the PC alternative by 8,000 gpd. Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB and CG alternatives, but that the PC alternative is preferable to the proposed project with respect to wastewater discharge.

c. Noise

The Company asserted that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to noise impacts (Exh. BEL-1, at 3-16).

In comparing the noise impacts of the proposed project to that of the technology alternatives, the Company assumed that each of the technology alternatives could be designed to achieve the same degree of continuous noise mitigation as would be achieved with the proposed project (id.). The Company stated, however, that the coal-fired alternatives would have added sources of noise due to coal usage which would be difficult to mitigate, including intermittent noise due to coal delivery and relatively continuous noise from coal crushing (id.). The Company stated that noise sources at the CG alternative, in addition to noise sources common to the other coal-based alternatives, would include the flare stack of the coal gasification plant (id.).

The record demonstrates that delivery and crushing of coal would increase noise impacts of the AFB, PFB, CG and PC alternatives relative to the proposed project.

Accordingly, the Siting Board finds that the proposed project is preferable to the AFB, PFB, CG and PC alternatives with respect to noise impacts.

d. Fuel Transportation

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to fuel transportation impacts (Exh. BEL-1, at 3-18). The Company stated that natural gas would be delivered to the site via an existing high-pressure interstate pipeline approximately one mile from the proposed site. The Company indicated that a new pipeline interconnect would be constructed from the proposed project to the existing facilities, with potential impacts to wetlands (id. at 3-17).

The Company stated that the four coal-fired alternatives would require rail delivery of coal as a practical matter and that the lack of rail access at the preferred site would make unlikely the construction there of a coal-fired project (id.).

With respect to transportation of fuel, the Company indicated that the coal-fired alternatives would require delivery of coal in quantities ranging from 1,248,120 tons per year for the CG alternative to approximately 1,594,205 tons per year for the AFB alternative (id. at 3-26). The Company indicated that the CG alternative, which would require less coal than the other considered coal-fired alternatives, would require 12,481 100-ton railcar-loads of coal, equivalent to more than 120 arrivals and departures per year, or at least two per week (id. at 3-17, 3-26). The Company stated that in addition to the coal deliveries, the PC alternative would require limestone or lime deliveries for SO_2 control (id. at 3-17). The Company stated that a coal-fired project would likely be sited in close proximity to existing rail lines with adequate capacity to accommodate coal deliveries, but that delivery of coal by rail would nonetheless likely involve additional impacts to other rail users and the communities through which the deliveries would pass (id.).[59] The Company further stated that the coal-based alternatives would require 30 days' on-site fuel storage, which would not be true of the proposed project (id.).

In comparing the transportation impacts of the coal-fired alternatives to the proposed project, the Siting Board notes that a coal-fired facility likely would be sited in proximity to existing rail lines. Because a potential rail route to the proposed site has not been identified, the specifics of the impacts along such a route, based on such factors as existing rail transport volumes, at-grade crossings, and the nature of abutting land uses, have not been identified and mitigation strategies have not been addressed. However, rail transport could have traffic and noise impacts over the life of the project.

The record demonstrates that the proposed project would limit fuel transportation impacts by connecting to existing high-pressure interstate pipeline facilities, but construction of a new pipeline interconnect from the proposed project to the existing facilities would likely involve impacts to wetlands. The record also demonstrates, however, that transportation of coal by rail would likely result in greater impacts overall and over time than would transportation of natural gas by pipeline.

Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to fuel transportation impacts.

e. Land Use

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to land use impacts (Exh. BEL-1, at 3-18). The Company indicated that it included both total land requirements and impacts to surrounding uses in evaluating the land use impacts of the proposed project and alternatives (id.). The Company indicated that the project's tallest structures would be the two 180-foot stacks and two 110-foot air cooled

59 The Company speculated that, assuming the availability of adequate rail infrastructure, the reliability of fuel transportation for the coal-based alternatives would likely be roughly comparable to the reliability of pipeline deliveries of natural gas (Exh. HO-RR-24; Tr. 2, at 101). The Company knew of no existing studies documenting this view, however (Exh. HO-RR-24).

condensers (id. at Figure 1.3-1). The Company indicated that construction of the proposed project would permanently alter 20.8 acres of the project site, a 125-acre, mostly wooded area, zoned industrial, and predominantly surrounded by forested land also zoned industrial, with some proximate areas of residential and recreational use (id. at 1-8, 6-65 to 6-66).

The Company stated that the coal-fired alternatives each would require at least 40 acres for the facility footprint, rail unloading and fuel storage areas (id. at 3-18). The Company stated that, in addition, the coal-fired alternatives would require a greater number of structures than the proposed project and that the scale of such structures, including the height of the buildings, stacks and cooling towers, would be significantly larger than the components of the proposed project (id.).[60]

The record demonstrates that the proposed project would require 20.8 acres within the proposed 125-acre site. The record further demonstrates that the scale and number of buildings required by the coal-fired alternatives would be greater than those required by the proposed project.

The Siting Board notes that on the basis of the size of the proposed site alone, construction there of the coal-fired alternatives as well as the gas-fired alternatives would likely be possible. The Siting Board further notes, however, the greater potential for a variety of land use impacts, including local noise and visual impacts, clearance of trees and other vegetation, and disturbance to wetlands, soils and natural habitat, resulting from the greater size and number of buildings associated with the coal-fired alternatives relative to the gas-fired alternatives.

Thus, given the facility footprint and building size requirements of the coal-fired alternatives relative to the proposed project, the land use impacts of the proposed project would be preferable at the proposed site. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to land use impacts.

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60 Additional structures associated with the coal-fired alternatives are for coal unloading and handling (Exh. BEL-1, at 3-18).

f. Solid Waste

The Company asserted that the proposed project would be preferable to the coal-fired alternatives with respect to solid waste impacts (Exh. BEL-1, at 3-19). In support of its assertion, the Company stated that the proposed project would generate minimal amounts of solid waste, approximately 35 tons per year, consisting primarily of incidental office and maintenance waste (id.). In contrast, the Company stated that the solid waste generated by the coal-fired alternatives, consisting primarily of ash or slag, would total 111,613 tpy for the CG and PC alternatives, and 372,905 for the AFB and PFB alternatives (id. at 3-19, 3-25). The Company stated that it assumed that solid waste from the coal-fired alternatives would be hauled off-site in railcars and that the ash potentially could be used as back-fill for coal mines (id. at 3-19).

The record indicates that the proposed project would produce significantly less solid waste than the coal-fired alternatives. Further, the large quantities of solid waste produced by the coal-fired alternatives would necessitate numerous rail trips to dispose of the waste off-site, although these rail trips would likely not be incremental. The Siting Board notes that the solid waste impacts of coal-fired technologies frequently can be mitigated by shipping coal ash to the mine head via the return trip of the train that transported the coal to the site. However, the record does not provide details of shipment of solid waste off-site and its effect on rail transport requirements. The Siting Board previously has found that, in the absence of detailed plans for the transport and disposal of solid waste in an environmentally beneficial way, solid waste impacts are greater for those technologies that generate greater amounts of waste. Millennium Power Decision, EFSB 96-4 at 65; Berkshire Power Decision, 4 DOMSB at 320-321; EEC (remand) Decision, 1 DOMSB at 351-352.

Accordingly, the Siting Board finds that, for the purposes of this review, the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to solid waste impacts.

g. Findings and Conclusions on Environmental Impacts

In comparing the overall environmental impacts of the proposed project and the coal-fired alternatives, the Siting Board has found that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to air quality impacts, water use, noise impacts, fuel transportation impacts, land use impacts and solid waste impacts. The Siting Board has also found that the proposed project would be preferable to the AFB, PFB and PC alternatives with respect to wastewater impacts, but that the PC alternative would be preferable to the proposed project with respect to wastewater impacts. The Siting Board notes that the slight preferability of the PC alternative with respect to wastewater impacts is outweighed by the clear preferability of the proposed project with respect to all other evaluated impacts.

Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to environmental impacts.

4. Cost

a. Description

The Company asserted that the proposed project would be superior to each of the technology alternatives considered in phase three with respect to cost (Company Brief at 51). In order to compare costs, the Company modeled the projected total revenue requirements of the proposed project and the AFB, PFB, CG and PC alternatives over both a 20- and a 30-year period beginning in January of the year 2000, the assumed in-service date of all units (Exhs. BEL-1, at 3-11 to 3-12; HO-A-6.1; HO-A-6.2).[61] The Company stated that it then summed the NPV of annual revenue requirements and calculated 20- and 30-year nominal levelized costs in dollars per megawatt-hour ("$/MWh") for each of the alternatives

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61 In projecting total revenue requirements for each alternative, the Company used consistent assumptions with respect to debt and equity ratios, debt term, interest rate, after tax return on equity, income tax rate, administration and general costs as a percentage of fixed O&M, property tax and insurance as a percentage of installed cost, depreciation, annual inflation rate, fuel escalation, and discount rate (Exh. BEL-1, at 3-22).

(Exh. BEL-1, at 3-11).

As noted in Section II.B.3, above, the Company indicated that the initial cost and performance data were generally taken from vendor supplied data for the proposed project and from the 1993 TAG and the U.S. Energy Administration's 1997 Annual Energy Outlook ("1997 Energy Outlook") for the technology alternatives (Exhs. BEL-1, at 3-12; HO-RR-21; HO-RR-23(S); HO-RR-23.2(red.); Tr. 2, at 54 to 59, 93 to 95). The Company stated that the 1997 Energy Outlook confirmed the ranking of the proposed project as significantly more cost effective than the technology alternatives (Exh. HO-RR-22).

With respect to fuel prices, the Company indicated that fuel price assumptions were based on the 1997 Energy Outlook (Exh. BEL-1, at 3-12; Tr. 2, at 95 to 99). The Company stated that its intent was to estimate, on a consistent basis, a year-2000 delivered fuel price specific to the New England region for each technology (Tr. 2, at 95-99). The Company indicated that it assumed that the proposed project and each alternative would run constantly, limited only by its individual equivalent availability factor (Exh. BEL-1, at 3-12, 3-21).

Table 4, below, details the total installed costs, O&M costs, and 20- and 30-year levelized cost for the alternative technologies. The Company indicated that the 20- and 30-year levelized cost of the proposed project would be significantly lower than that of the alternative technology units (id. at 3-12).

Table 4

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	ANP Bellingham	AFB	PFB	CG	PC
Fuel	Gas	Coal	Coal	Coal	Coal
Unit Size (MW, Nominal)	545	545	545	545	545
Fuel Price ($/MMBtu)[1,2]	3.19	1.76	1.76	1.76	2.02
Equivalent Availability (percent)	92	90.4	80.8	85.7	85.5
Full Load Heat Rate (Btu/kWh)	6,700	9,796	8,959	8,090	9,618
Total Plant Investment[3] ($/kW)	*	1,737	1,517	1,971	1,759
Fixed O&M ($/kW-yr)[2,4]	*	84.79	87.70	105.84	107.43
Variable O&M ($/kWh)[2]	*	6.64	4.06	0.61	2.80
20-Yr Nominal Levelized Cost ($/kWh)	*	.0733	.0716	.0717	.0779
30-Yr Nominal Levelized Cost ($/kWh)	*	.0748	.0711	.0728	.0795

1. Year-2000 fuel prices for gas-fired units are based on 100 percent load factor.
2. First year cost based on in-service date of January 1, 2000.
3. Based on in-service date of January 1, 2000.
2. Total Plant Investment includes total cost of plant, administration & general costs, property taxes and insurance.

* Total plant investment, fixed O&M, variable O&M, 20-year nominal levelized cost and 30-year nominal levelized cost for the proposed project were less than the corresponding values for each of the other considered alternatives (Exhs. HO-A6.1-C (conf.); HO-A6.2-C (conf.)).

Sources: Exhs. BEL-1, at 3-21, 3-23; HO-A-6.1; HO-A-6.2.

b. Analysis

The record indicates that the 20- and 30-year levelized costs of the proposed project would be less than the 20- and 30-year levelized cost of each of the technology alternatives, given the Company's assumptions regarding capital costs, interest rates, and fuel prices.

Accordingly, for the purposes of this review, the Siting Board finds that the proposed project would be preferable to the AFB, PFB, CG and PC alternatives with respect to cost.

5. Reliability

a. Description

The Company asserted that the proposed project would be preferable to each of the technology alternatives with respect to reliability (Exh. BEL-1, at 3-20). In analyzing the reliability of the proposed project and the technology alternatives, the Company assessed (1) the anticipated availability of each technology and corresponding energy source, and (2) the likelihood that the technology would be available at the time for which the first need for new capacity has been identified (id. at 3-19 to 3-20).

The Company stated that projects that rely on a mature, commercially available technology have a reliability advantage over technologies whose expected cost and performance characteristics have yet to be fully demonstrated and are based primarily on engineering estimates (id.). The Company indicated that the proposed project and the PC alternative use technologies classified as mature in the 1993 TAG and would therefore have a reliability advantage over the AFB technology, classified as commercial, and the PFB and CG technologies, classified as demonstration level technologies (id.). The Company indicated that the anticipated availability of the proposed project, 92 percent, surpassed the anticipated availability of the other technology alternatives (see Table 4, above) (id. at 3-19). With respect to the likely high availability of the proposed project, the Company also emphasized the proposed project's limited overhaul maintenance requirements and readily available replacement parts (id.). In addition, the Company anticipates a firm gas supply for the proposed project (Tr. 3, at 147) (see Section II.C.3.b, below).

b. Analysis

The record demonstrates that the availability of the proposed project would be 92 percent and that the technology of the proposed project is classified as mature by the 1993 TAG. The Company has also indicated that the proposed project likely would have a firm gas supply (see Section II.C.3.b, below).

In comparing the reliability of the proposed project to that of the alternatives, all of which are coal-fired, the Siting Board first notes that the record in this case is inconclusive with regard to differences in the reliability of a natural gas supply delivered via pipeline and a coal supply delivered via rail.

In comparing the reliability of the proposed project to the reliability of the AFB alternative, the Siting Board notes that the availability factor for the AFB alternative is assumed to be 90.4 percent, 1.6 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the AFB alternative, does not represent a significant difference for the purposes of this review. The proposed project, however, is classified as a mature technology, denoting significant operating experience, while the AFB alternative is classified as a commercial technology, denoting limited operating experience. Accordingly, the Siting Board finds that the proposed project would be preferable to the AFB alternative with respect to reliability.

In comparing the reliability of the proposed project to the reliability of the PFB alternative, the Siting Board notes that the availability factor for the PFB alternative is assumed to be 80.8 percent, 11.2 percent less than that of the proposed project, indicating the somewhat greater availability of the proposed project. In addition, the proposed project is classified as a mature technology, denoting significant operating experience, while the PFB alternative is classified as a demonstration technology. The CG alternative, with an availability factor of 85.7 percent, fares better than the PFB alternative when compared to the proposed project, but it, too, is classified as a demonstration technology, i.e., some limited operating experience exists but the technology requires further research and development to qualify as commercial or mature. Accordingly, the Siting Board finds that the proposed project would be preferable to the PFB and CG alternatives with respect to reliability.

In comparing the reliability of the proposed project to that of the PC alternative, the Siting Board notes that the availability factor of the PC alternative is 85.5 percent, 6.5 percent less than that of the proposed project. Such a difference in availability of the two technologies, while indicating that the proposed project would be slightly preferable to the PC alternative, does not represent a significant difference for the purposes of this review. In addition, both technologies are classified as mature. Accordingly, the Siting Board finds that the proposed project and PC alternative would be comparable with respect to reliability.

Therefore, the Siting Board finds that the proposed project would be comparable to the PC alternative and preferable to the AFB, PFB and CG alternatives with respect to reliability.

6. Comparison of the Proposed Project and Technology Alternatives

In order to establish that a proposed project is preferable to technology alternatives in its ability to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternative approaches in its ability to address the previously identified need in terms of environmental impact, cost, and reliability.

In Sections II.B.3, II.B.4 and II.B.5, above, the Siting Board has compared the proposed project to generating technology alternatives that have been determined capable of meeting the identified need, on the basis of their specific environmental impacts, costs and reliability. Based on its comparison, the Siting Board has found that the proposed project would be: (1) preferable to the AFB, PFB, CG and PC alternatives with respect to environmental impacts; (2) preferable to the AFB, PFB, CG and PC alternatives with respect to costs; and (3) comparable to the PC alternative and preferable to the AFB, PFB and CG alternatives with respect to reliability.

Accordingly, the Siting Board finds that the proposed project is superior to the AFB, PFB, CG and PC alternatives with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

C. Project Viability

1. Standard of Review

a. Existing Standard

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 71; Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 346.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. Millennium Power Decision, 96-4, at 72; Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 345.[62]

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project will actually go into service as planned. The Company asserted that the Siting Board should consider the proponent's access to financial resources as well as the competitiveness of a

[62] The Siting Board has issued a Notice of Inquiry in order to reexamine its fundamental standard of review for viability in light of ongoing changes in the electricity industry. Until such time as the Siting Board either affirms its current standard of review or articulates a new one, we will continue to apply our existing standard of review, while remaining flexible as to the evidence required to meet that standard.

proposed project in the deregulated market in order to assess the financiability of a proposed merchant plant (Exh. BEL-1, at 4-2).

ANP stated that it had budgeted funds necessary to finance the development of the proposed project as well as two additional merchant facilities proposed for Massachusetts and Maine (Exh. HO-V-10). ANP Bellingham stated that its parent American National Power would use cash flow from ongoing operations to fund development of the proposed project (Exh. BEL-1, at 4-2). ANP stated that National Power ("NP") would provide 100 percent equity funds during the construction period and possibly throughout the operating period, depending on the cost of debt (id.). The Company stated that it expected that any funds borrowed by NP to fund the project would be borrowed on the balance sheet at a cost of debt below that which would be available under project financing (Exh. BEL-1, at 4-2 to 4-3). The Company asserted that the use of equity funds would lower costs and provide other viability advantages such as the elimination of the restrictions often attached to debt funding and elimination of any external milestones precedent to project financing (id.).[63]

The Company indicated that American National Power, the United States development and operating affiliate of NP, has an ownership share totalling 678 MW in 1,536 MW of generating capacity in the United States and that NP has investments in and/or operates approximately 24,100 MW of generating capacity throughout the world (id. at 4-3). Further, the Company asserted that NP is one of the financially strongest generating companies in the world, with 10.2 billion dollars of market capitalization, and therefore has the capability to finance the one-half billion dollars required for the Blackstone and Bellingham facilities (id.; Tr. 3, at 107). Mr. Pedrick added that, since privatization, NP has invested more than 1.5 billion dollars in the United Kingdom and over a billion dollars in other international projects (Tr. 3, at 108).

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63 The Company explained that banking and legal fees would be eliminated and that the cost of debt after the facility is complete and has commenced commercial operations would be less than the cost of debt borrowed earlier in project development (Exh. BEL-1, at 4-2).

To demonstrate the financial viability of the proposed project, the Company provided nine pro forma analyses showing the internal rate of return ("IRR") under base, high and low case dispatch factors and base, high and low case revenue assumptions (Exh. V-14 (conf); Tr. 3, at 83-84). Mr. Haupt stated that: (1) the base case dispatch factor was 90 percent; (2) the base case revenue assumption was consistent with assumptions used in the economic efficiency analysis; and (3) fuel costs, constant in all pro formas, were determined from a study commissioned by the Company (Tr. 3, at 84, 88-89). He stated that the high and low dispatch cases were a five percent increase and decrease, respectively, of the base case and that the high and low revenue cases were a ten percent increase and decrease, respectively of the base case (Tr. 3, at 84). He stated that each pro forma analysis, with the exception of the analysis that combines the low case dispatch factor with the low case revenue assumptions, shows an IRR that would be acceptable to the Company (id. at 84-85). In addition, he argued that IRRs under low case revenue conditions likely would be higher than what is projected in the pro formas because gas costs likely would be lower than assumed in a low-revenue market (id. at 90). He also indicated that the pro formas reflect the fact that debt would be incurred by NP and not by the proposed project (id. 86-87).

The Company indicated that this is the first plant that would be built by ANP exclusively as a merchant plant and that the power would be marketed by ANP Bellingham Energy Company (id. at 64-65). The Company stated that it is attempting to develop a fleet of assets in New England and that each generating facility would be bid into the pool, considering the other generating facilities owned by the Company (id. at 66). The Company estimated that the proposed facility likely would run 90 percent of the time it is available due to its low cost (id. at 67). The Company stated that power would be sold through the pool by bidding into the pool an amount equal to the project's cost or an amount slightly above its variable costs, but lower than the market-clearing price (id.). ANP stated that power also could be sold through bilateral agreements if the negotiated price was higher than the pool price, but noted that its economic assessment shows financial viability assuming pool prices (Tr. 3, at 111-112). ANP added that its economic efficiency analysis also demonstrates the proposed project's competitiveness in the deregulated market (Exh. BEL-1, at 4-1).

The Siting Board recognizes that the proposed project, like the three most recent generating projects reviewed by the Siting Board, is being financed as a merchant plant. Further, a number of petitions pending before the Siting Board involve projects categorized as merchant plants. The nature of the new power supply market is such that long-term power contracts will not be the vehicle for selling the output from the proposed facilities. Therefore, as in prior cases, the Siting Board will focus on the financial experience of the proponent, its ability to market the output of the proposed facility, financial indicators such as IRRs, and the ability to produce reliable, low cost electricity. Evidence of signed long term contracts will not be required to establish financiability.

NP has committed to finance the proposed project internally. The record indicates that NP has a broad range of experience in the overall project development process, including financing, and has developed numerous generating facilities worldwide. NP also has substantial capital resources for equity investment in power projects.

The range of assumptions provided by the Company in its pro formas is generally reasonable and consistent with Siting Board reviews in prior proceedings. The Company's pro formas indicate that the proposed project would provide a favorable IRR under differing levels of dispatch and revenue.

Based on the foregoing, the Siting Board finds that the Company has established that its proposed project is financiable.

b. Construction

In considering a proponent's strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. Millennium Power Decision, EFSB 96-4, at 79; Berkshire Power Decision, 4 DOMSB at 332. ANP stated that, with NP, it has developed and constructed several combined cycle power plants totaling over 4,000 MW over the past ten years, (Exh. BEL-1, at 4-4). ANP added that the majority of the combined cycle facilities owned or operated by ANP and NP have been constructed under turnkey EPC contracts where the contractor was also the equipment vendor (id.).

Here, the Company indicated that it is currently negotiating an EPC contract with ABB (id. at 4-5). The Company stated that since 1939, ABB has supplied or has under construction over 1,000 gas turbines in 470 power stations worldwide, including more than 125 combined cycle plants, of which approximately 50 percent were supplied on a turnkey basis (id. at 1-4). ANP stated that ABB will design and construct the plant to achieve a 20.5- month construction schedule (id. at 4-5). In addition, ANP stated that ABB has agreed to guaranteed heat rate, output, and schedule terms with liquidated damages on a "keep-whole" basis such that the viability of the proposed project would not be jeopardized if any of the guarantees were not met (id.; Tr. 3, at 94-96). ANP stated that ABB also has agreed to a guaranteed availability with a significant penalty if availability terms are not met (Tr. 3, at 95-96).

The Company stated that the EPC contract will provide the owner with a fixed price for the proposed project based on an agreed scope of work (id. at 100). The Company stated that ABB will be responsible for all design, engineering, procurement, delivery, construction tasks, installation and training needed to bring the plant into operation at guaranteed output, heat rate, emissions, noise and other performance levels (id. at 100-101). The Company explained that the EPC contract will include provisions for: (1) a fixed price with payments on a milestone basis; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, or (b) operation guarantees; (4) bonuses for early completion and improved performance; and (5) insurance (id. at 100-103). The Company noted that a minimum availability of 92 percent is projected for the life of the proposed project (id. at 64-65).

The Company indicated that the ABB GT24/26[64] is a relatively new combustion turbine developed by ABB over the last several years (id. at 53). ANP stated that there are currently four ABB GT24/26 turbines operating worldwide in the single-cycle mode, and a number of other ABB GT 24/26 turbines under construction or under contract (id. at 53-55).

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64 The Company indicated that the ABB GT26 is the European version of the ABB GT24 (Tr. 3, at 53-54).

Mr. Haupt stated that ANP/NP has a history of using new, state-of-the-art combustion turbine technology which it considers to be the most competitive technology in the field (id. at 56-57). Mr. Pedrick stated that due to the Company's background in owning and operating generating facilities, it is able to work with combustion turbine manufacturers to determine the technical risks that prevail and to work with them to ensure that the plants will be safely constructed and operated (id. at 57). Mr. Haupt added that although there is a higher degree of risk associated with a newer technology, aggressive guarantees from ABB with respect to heat rate, output and availability will mitigate those risks to the Company (id. at 59).

The Company indicated that none of ANP/NP's existing facilities use steam augmentation and that it is not aware if any of the ABB GT24/26 units in progress will use this technology (id. at 61-62). However, the Company maintained that ABB is familiar with steam augmentation technology and that the technology involves no specific technical risks other than a slight increase in the complexity of the machine and an increase in the commissioning period at the end of construction (id. at 62-63).

In addition, the Company indicated that it has experience in developing more than one facility of this size and type in the same time frame (Exh. HO-V-17). In addition to the Bellingham and Blackstone units, ANP stated that it is currently developing two merchant facilities in Maine and Texas, and that NP is currently developing a number of projects worldwide (id.).

The Company stated that the proposed project would be interconnected with the regional electric transmission grid via a short tie line to the existing NEPCo 303 transmission line, which operates at 345 kV and which is located on a 325-foot wide ROW that traverses the eastern portion of the site (Exh. BEL-1, at 6-22). ANP provided a draft system impact study which details the impacts to the NEPCo and BECo transmission systems of interconnecting both the proposed facility and the proposed Blackstone facility to the transmission grid, and which identifies system-wide upgrades that will be required for interconnection (Exh. HO-EE-14.1). These system wide upgrades include the reconductoring of the NEPCo 303 transmission line between the proposed facility and the West Medway substation to the north, reconductoring of additional transmission lines, and upgrades to terminal equipment at a number of substations (Exh. HO-EE-14.1, at 23-24). The Company added that it has been notified by NEPCo that the reliability of the 303 circuit has historically been better than the 345 kV system average (Exh. HO-V-38.1).

In the past, the Siting Board has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is likely to be constructed on schedule and will be able to perform as expected. Millennium Power Decision, EFSB 96-4, at 82; Dighton Power Decision, EFSB 96-3, at 26-27; Altresco-Pittsfield Decision, 17 DOMSC at 380.

Here, the Company has not submitted a draft or final EPC contract. However, the record in this proceeding indicates that the Company and ABB have significant experience in the design and construction of generation plants which use technology similar to that proposed for this project and have successfully completed comparable projects. The Siting Board accepts that the Company's experience in negotiating EPC contracts for comparable projects contributes strongly to its ability to negotiate an acceptable final EPC contract. It also notes that the Company has stressed its intentions to provide low cost, clean power and has stated that its construction practices are structured to fulfill these objectives. However, in the absence of a final EPC contract between ANP and ABB, the record contains no assurance that ABB actually will be the EPC contractor for this project. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed EPC contract between ANP and ABB, or a comparable entity, that contains provisions that provide reasonable assurance that the project would perform as a low cost, clean power producer.

The Siting Board notes that while an interconnection study has been prepared, the Company has not entered into a signed interconnection agreement with NEPCo enabling transmission access. Failure to negotiate a final interconnection agreement acceptable to both parties would prevent the proposed project from providing energy to the Commonwealth and the region. See Millennium Power Decision, EFSB 96-4, at 82-83; Berkshire Power Decision, 4 DOMSB at 336. However, if the Company provides a signed interconnection agreement, it will be able to establish that its proposed project is likely to be capable of being dispatched as expected. Therefore, the Siting Board requires the Company to provide the

Siting Board with a copy of a signed interconnection agreement between the Company and NEPCo.

Finally, the Siting Board notes that the proposed ABB GT24/26 turbine has commercial operating experience in the single cycle rather than combined cycle mode. While the record indicates that ABB would be responsible for correcting any problems with the turbine, the proposed project cannot go forward as planned if there are unexpected delays in turbine development or testing. The Siting Board reiterates that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). Should the ABB GT24 turbine be unable to perform substantially as expected, ANP would be required to notify the Siting Board as explained in Section IV, below.

Accordingly, upon compliance with the above conditions that the Company provide the Siting Board with (1) a copy of a signed EPC contract between ANP and ABB or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPCo providing the proposed project with access to the regional transmission system, the Siting Board finds that the Company will have established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives.

The Siting Board has found that the Company has established that its proposed project is likely to be financiable. The Siting Board has also found that, upon compliance with the above conditions relative to a signed EPC contract and a signed agreement for access to the regional transmission system, the Company will have established that its proposed project is likely to be constructed within applicable time frames and capable of meeting the Company's performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above conditions, the Company will have established that its proposed project meets the Siting Board's first test of viability.

3. Operations and Fuel Acquisition

a. Operations

In determining whether a proposed NUG project is likely to be viable as a reliable, least-cost source of energy over the planned life of the proposed project, the Siting Board evaluates the ability of the project proponent or other entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Millennium Power Decision, EFSB 96-4, at 84; Dighton Power Decision, EFSB 96-3 at 27; Altresco-Pittsfield Decision, 17 DOMSC at 381-382. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent has been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks have historically been enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the facility. Millennium Power Decision, EFSB 96-4, at 84; Berkshire Power, 4 DOMSB at 337-339; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

ANP stated that the proposed project would be competitively priced, new, efficient and clean (Exh. BEL-1, at 1-1). ANP asserted that its experience owning and operating combined cycle plants over the last decade (including its recent experience owning and operating the Milford Power plant), NP's technical resources and ANP's intention to operate the facility, ensure that the proposed project will be operated reliably and cost-effectively to compete in the deregulated electric market (id. at 4-11). Mr. Haupt stated that ANP Operating Company, a company 100 percent owned by ANP, will operate the proposed facility (Tr. 3, at 114-115). He further stated that ANP Operating Company currently operates the Milford Power facility and is expected to operate all of ANP's merchant plants (id.). He added that a contract would be signed with ANP Operating Company during the construction period because operations personnel will be hired at that time to help facilitate the construction of the proposed facility (id. at 114). The Company stated that NP owns and operates generating facilities totaling 17,000 MW in the United Kingdom (id. at 115-116).

ANP provided a summary of its O&M program (Exh. BEL-1, at 4-6 to 4-11). ANP stated that its O&M program will include procedures for: (1) normal plant O&M functions;

(2) catastrophic avoidance; (3) emergency preparedness; (4) incremental improvement in the condition and capability of the facility; and (5) equipment status monitoring and documentation (id. at 4-6). The Company stated that, during operation, the facility would be maintained in optimal condition using proactive, predictive and preventive maintenance techniques to minimize disruptions to production and downtime (id. at 4-9).

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance objectives. Millennium Power Decision, EFSB 96-4, at 85; Dighton Power Decision, EFSB 96-3, at 28; Altresco-Pittsfield Decision, 17 DOMSC at 382. However, provision of such a contract is required only "[i]n a case where the proponent has relatively little experience in the development and operation of a major energy facility...". Millennium Power Decision, EFSB 96-4, at 84; Berkshire Power Decision, 4 DOMSB at 337-339; Altresco-Pittsfield Decision, 17 DOMSC at 382-383. ANP has demonstrated that it has considerable experience operating major energy facilities both in Massachusetts and in other states and countries, and has indicated that it intends to operate the proposed facility through its wholly-owned subsidiary, ANP Operating Company. Further, ANP has provided a summary of its anticipated O&M plan, which provides reasonable assurance that the project would perform as a low-cost, clean power producer. Accordingly, the Siting Board finds that the Company has established that the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

The Board's conclusions regarding the Company's O&M assume that the final contract between ANP and ANP Operating Company will be consistent with the O&M plan outlined during the proceedings. In Section IV, below, the Siting Board requires ANP to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue. Therefore, if the terms of the O&M contract differ significantly from the O&M plan considered in this analysis, the Company shall describe the changes and explain how such changes would affect the Company's objectives to provide low-cost, clean power.

b. Fuel Acquisition

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

ANP stated that gas supply strategies should be as flexible as possible in a merchant plant environment (Tr. 3, at 152). The Company asserted that its gas supply strategy would ensure the delivery of natural gas to the proposed project on a reliable basis at a low price that would reflect competitive prices in the market and supply areas (Exh. BEL-1, at 4-16). ANP indicated that it plans to connect to the Algonquin Gas Transmission Company ("AGT" or "Algonquin") pipeline located approximately one mile to the north of the site, and that AGT has initiated proceedings for construction of the connecting pipeline with the Federal Energy Regulatory Commission ("FERC") (Exh. BEL-1, at 1-13; Tr. 3, at 144). ANP indicated that although it does not currently plan to physically interconnect the proposed project with the Tennessee Gas Pipeline Company ("TGP"), it may enter into an exchange agreement with TGP and AGT whereby it could contract with both pipelines through either one renting space to the other (Tr. 3, at 145).

The Company stated that it anticipates a firm gas supply for the proposed project (id. at 147). ANP stated that it is considering three general categories of supply arrangements including: (1) firm supplies that are delivered by a supplier directly to the plant meter; (2) firm supplies that are delivered to a liquid point of receipt[65] on the TGP or AGT system by a supplier with firm transportation from that point to the proposed facility; and (3) a supply from the east or north of the site that would be received through displacement (id. at 147-148, 152-153). The Company indicated that it issued a Request for Proposals ("RFP") for a 365-day gas supply for the proposed Bellingham facility and two additional generating facilities proposed by ANP in Blackstone, Massachusetts and Gorham, Maine (id., at 151-152, 157-158). Mr. Kasle stated that the offers from suppliers in response to the RFP were well in excess of the gas supply requirements for the three proposed facilities (id.

65 The Company explained that a liquid point of receipt is a point on the interstate pipeline where ownership of the commodity is transferred (Exh. BEL-1, at 4-17).

at 159). The Company stated that the suppliers who responded to the RFP were equally reliable and that the responses therefore would be evaluated on the basis of flexibility of the supply arrangements[66] and pricing[67] (id. at 153). ANP stated that it anticipated gas supply contracts of varying lengths, but generally three to five years with evergreen provisions (id. at 161-162). In addition ANP stated that it would consider an arrangement whereby the electricity buyer would provide gas for the project (id. at 154-155).

The Company stated that it had initiated negotiations with potential suppliers and that a gas supply would be in place for the proposed facility prior to the commencement of construction (id. at 151). The Company stated that it was certain that the supplies offered in the RFP would still be available at the time the contracts are signed (id. at 167). The Company explained that the suppliers who responded were large players in the industry who buy their gas from a number of sources (id.). In addition, the Company explained that such factors as its internal financing and progress in project development make ANP a good market from a supplier's point of view and that it therefore did not anticipate that supply offers would be withdrawn in favor of competing generating facilities (id. at 167-168).

The Company indicated that firm transportation would be arranged by the supplier to the facility or by ANP back to a liquid point of receipt (id. at 148). The Company stated that it has been discussing transportation from liquid points of receipt with both TGP and AGT (id. at 149). The Company noted that if supplies were obtained from the north or east of the site via displacement, firm transportation would not be necessary to ensure reliability (id. at 149-150). The Company stated that its fuel supply arrangement for firm supply and transportation would enable the proposed facility to operate without fuel oil backup (id. at 151-152).

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66 Mr. Kasle explained that under more flexible supply arrangements, the Company would not be required to take all the gas contracted for on a daily or monthly basis under minimum load conditions (Tr. 3, at 153-154).

67 Mr. Kasle indicated that the pricing included in the responses was market-based and therefore in the range that had been anticipated (Tr. 3, at 155).

The Company indicated that it has gained experience in contracting for similar gas supply and transportation arrangements for its Milford Power facility (Exhs. HO-V-19; HO-V-31). In addition, Mr. Kasle, who is responsible for developing the fuel strategy, sourcing fuel supplies and transportation and negotiating contracts, indicated that he had twelve years of energy-related experience, including experience in buying and selling natural gas and transportation on a short and long term basis, and in developing fuel supply strategies for greenfield power projects (Exh. BEL-6). Further, Mr. Mitchell, who has been assisting the Company in developing a gas purchase and transportation strategy, stated that he had extensive experience in gas supply and transportation strategy and procurement, including evaluating gas supply and transportation economics, regulations, rates, supply options, and negotiating contracts (Exh. BEL-7).

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. Millennium Power Decision, EFSB 96-4, at 90; Dighton Power Decision, EFSB 96-3, at 28; Berkshire Power Decision, 4 DOMSB at 343. The Siting Board has recognized that, in considering a petitioner's fuel acquisition strategy, it is appropriate to consider the need for flexibility, the expected shorter time frame of PPAs in a restructured electric industry, and the industry-wide shift away from long-term gas supply contracts. Millennium Power Decision, EFSB 96-4, at 90; Dighton Power Decision, EFSB 96-3, at 28; Berkshire Power Decision, 4 DOMSB at 343. Nevertheless, the Siting Board must still be convinced that a low-cost, reliable fuel supply will be available to a proposed project in order to determine that a proposed project will be capable of providing a necessary energy supply consistent with its mandate.

In past decisions, the Siting Board generally has reviewed final fuel transportation and/or supply contracts between proponents and pipeline companies. While the Siting Board has not required proponents to submit signed long-term fuel supply contracts in recent cases, it generally still has required firm transportation contracts from a major interconnection point as assurance that a proponent's gas supply strategy is viable.

In a recent review of a gas-fired facility with a back-up oil supply, the Siting Board acknowledged that a firm transportation contract from an interconnection point just outside

New England to the proposed project site in Massachusetts demonstrated viability of the petitioner's gas supply strategy. Berkshire Power Decision, 4 DOMSB at 344. Upstream of that gas supply point, the Siting Board accepted a gas supply management arrangement whereby a gas service company would be responsible for the daily workings of all of the gas supply and gas transportation contracts for the proposed facility. Id.

Here, the Company has presented a fuel acquisition strategy that involves the intent to contract for a 365 day firm natural gas supply that would be: (1) delivered to the proposed facility meter by the supplier; (2) delivered to an interconnection point in the region by the supplier with a firm transportation agreement from the point to the proposed facility; or (3) delivered to the proposed facility via displacement if the supplies are obtained from areas to the north or east of the proposed facility. The Company noted that firm transportation would not be required if the gas was delivered via displacement. The Company has issued an RFP for gas supply and has received offers well in excess of the requirements of the proposed facility and has entered into negotiations for firm transportation arrangements with both AGT and TGP. The Company plans to have its gas supply contracts in place prior to the start of construction. In addition, the Company has demonstrated that it has experience in procuring fuel for comparable facilities including a facility in Massachusetts.

It is likely that the fuel supplies selected by the Company will be low cost, due to its ability to take advantage of a variety of gas suppliers and transportation options. In addition, each of the three transportation options being considered by the Company, alone or in combination, would provide assurance that supplies would be delivered to the proposed project on a firm basis. Accordingly, the Siting Board finds that the Company has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project.

However, the Company has not yet entered into contracts for gas supply and transportation. The Siting Board's conclusions regarding the Company's fuel acquisition strategy assume that the final contracts will be consistent with one of the fuel supply and transportation options outlined during this proceeding. In Section IV, below, the Siting Board requires ANP to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue.

Therefore, the Company shall notify the Siting Board if contracts are executed that provide for fuel transportation arrangements other than those considered in this analysis, and submit to the Siting Board a discussion of the changed transportation arrangements and explain how such arrangements would affect the cost and reliability of the project's gas supply.

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

4. Findings and Conclusions on Project Viability

The Siting Board has found that upon compliance with the conditions in Section II.C.2, above, ANP will have established that (1) the proposed project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project.

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

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Site Selection Process

The Siting Board has a statutory mandate to implement the energy policies in G.L. c. 164 §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164 §§ 69H and 69J. Further, G.L. c. 164 § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347.

1. Standard of Review

In order to determine whether a facility proponent has shown that siting plans for its proposed project are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347.

To determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Board has previously required the proponent to satisfy a two-pronged test. The proponent has had, first, to 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. Millennium Power Decision, EFSB 96-4 at 94; Dighton Power Decision, EFSB 96-3 at 31; Berkshire Power Decision, 4 DOMSB at 347. Second, the proponent has had to establish that it identified at least two noticed sites or routes with some measure of geographic diversity. Millennium Power Decision, EFSB 96-4 at 94-95; Dighton Power Decision, EFSB 96-3 at 32; Berkshire Power Decision, 4 DOMSB at 347-348.

As indicated in Section I.D, above, the Siting Board allowed ANP to withdraw its alternate site from Siting Board consideration.[68] The second part of this test therefore was adapted to the review of a petition with only one noticed site. Specifically, ANP must show that it has examined a reasonable range of practical facility siting alternatives by: (1) establishing 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 proposed site, and (2) identifying at least two potential facility sites with some measure of geographic diversity. This adapted standard of review helps to ensure that the proposed facility is sited so as to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

2. Development and Application of Siting Criteria

The Company indicated that its initial site selection process was designed to: (1) identify a reasonable universe of site alternatives; (2) apply a consistent set of objective site evaluation criteria; and (3) select from the identified universe of site alternatives a site which minimizes cost and environmental impacts while ensuring supply reliability (Exh. BEL-1, at 5-2).

a. Description

The Company stated that it narrowed its site search to the Commonwealth of Massachusetts for the following reasons: (1) Massachusetts' location within the area proximate to most significant load centers in the region; (2) regulatory preference in Massachusetts for least-cost, least environmental impact generating facilities; and (3) the Commonwealth's spearheading of electric industry restructuring and the resulting favorable market environment for merchant plants (id. at 5-3).

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68 As outlined in ANP Bellingham Energy Company, EFSB 97-1, Hearing Officer Procedural Order, December 16, 1997, at 2, formal noticing of two sites for a proposed generation facility such as ANP Bellingham is not required as a matter of law or Siting Board regulation and is not necessary as a matter of policy.

The Company indicated that its site selection process initially focused on locations proximate to major natural gas transmission pipelines and electric transmission systems throughout Massachusetts (id. at 5-2). The Company stated that it identified two significant node locations, and that it concentrated its site selection search along "corridors" in the area of these identified node locations, one in the Merrimack/Concord River Valley ("northern node") and the second in the Blackstone River Valley ("southern node") (id.). The Company indicated that it defined the corridors used in its site selection process as the area along the northern and southern nodes with direct access to electric transmission and within one mile of the interstate gas pipeline system (id. at 5-3 to 5-4). The Company indicated that it reviewed areas within each corridor to identify potentially available parcels that met a set of minimum threshold criteria, but noted that it subsequently narrowed its search to sites in the southern node on the basis of electric transmission issues (id. at 5-2).

The Company stated that contacts to gauge receptivity with towns and with landowners proceeded in tandem with the site evaluation process. The Company indicated that in some instances, a contacted municipality identified particular sites not necessarily within the defined site selection corridor and that, if appropriate, these municipality-identified sites were included for assessment and were eliminated or carried forward for review on the same basis as other sites (id. at 5-5).

The Company established a series of threshold criteria by which it evaluated potential sites identified using the "corridor approach" described above (id. at 5-4). These criteria were: the site must be vacant; the site must have no mapped endangered species habitat; the site must have a parcel size of at least 25 acres, with at least 10 acres of "buildable" land (defined as no indicated wetlands or excessive slopes); and the site and interconnects must be located within a single community (id.). The Company conducted its evaluation first on the basis of United States Geological Survey ("USGS") and geographic information systems ("GIS") mapping; second, with the aid of community zoning and tax maps; and third, via site reconnaissance ("ground truthing") (id. at 5-5). The Company stated that following the completion of ground truthing, 17 sites in the southern node were carried forward for further evaluation (id.).

The Company stated that sites which met its minimum threshold criteria were then assessed against a set of 20 site screening criteria: (1) ease of electrical interconnection; (2) ease of gas interconnection; (3) site size/buffering potential; (4) site topography and geology; (5) potential for site contamination; (6) water availability; (7) wastewater disposal availability; (8) adequacy of roadway/rail infrastructure; (9) dispersion environment; (10) proximity to airports; (11) surface water resources; (12) groundwater resources; (13) proximity to wetland/floodplain resources; (14) endangered species/significant habitat; (15) land use compatibility; (16) compatibility with zoning/community development designation;
(17) proximity to sensitive receptors; (18) potential for compliance with local or state noise regulations; (19) project visibility and compatibility with existing viewshed; and (20) level of community support (id.).

To derive an overall suitability score, weighting factors (on a 1-10 scale, with 10 indicating criteria of greatest importance) were developed for each criterion based on the project team's judgment of the relative importance of each criterion in terms of overall site suitability (id. at 5-6 to 5-15). The Company then evaluated each potential site by assigning suitability ratings of high (two points), medium (one point) or low (zero points) for each criterion (id. at 5-15). The Company derived an overall site suitability score for each of the 17 sites in the southern node by totalling the individual weighted scores for each of the 20 screening criteria (id.).

The Company stated that six sites emerged in the top scoring group based on its evaluation process (id.). The Company indicated that it eliminated its top-ranked site after learning from the owner that the site was under consideration for sale for residential development and that the owner was unwilling to enter into an option agreement (id.). The Company stated that each of the five remaining sites was further evaluated based on detailed discussions with community officials and landowners (id.). The Company stated that, based on its investigations, the proposed site was confirmed as a viable site, and that strong site attributes and serious community support presented persuasive reasons to pursue the site further (id. at 5-16).[69] The Company pointed out that others of the top scoring sites presented significant development potential, and were of interest to the Company with respect to a second contemplated generation project (id.).

The Company asserted that it did not use, and would not advocate using, numerical scoring alone to select its preferred site. The Company's witness argued that site selection was best approached as a bifurcated process, with a short list produced based on a numerical system and a final determination of rank based on the experience and judgment of the Company and its consultants (Tr. 6, at 34 to 35).

The three active intervenors in the instant proceeding, the Town of Franklin, the Bellingham Conservation Commission and local resident Joseph Goulart, argued that the Company's application of its site selection protocol was flawed, and that there were other sites among the Company's top scoring group, including a second site in Bellingham known as "Bellingham 4", which were superior to the Company's proposed site for the project (Town of Franklin Brief at 10 to 17; BCC Brief at 2 to 3; Joseph Goulart Brief at 2 to 6).

The Town of Franklin and Mr. Goulart suggested their own different weighting and suitability ratings for the Company's screening criteria; these ratings would result in a change in the rankings within the highest-ranked group of sites, and specifically, a lowering of the ranking of the proposed site (Town of Franklin Brief at 11 to 16; Goulart Brief at 2 to 5). In addition, Mr. Goulart argued, first, that the Company emphasized economic considerations over environmental factors, and, second, that the Company applied its criteria inconsistently to the 17 sites evaluated in the southern node, especially with respect to community support, noise and gas interconnection impacts, and land use compatibility (Goulart Brief at 2 to 6).

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69 The Company indicated that its "community support" criterion was initially defined to focus on support from public officials and historic public reaction to industrial development (Tr. 5, at 56). The Company stated, however, that it had on a number of occasions received public input from those attending presentations about the proposed project made to officials in meetings open to the public (id. at 47 to 49, 56 to 57). The Company indicated that in later stages of the site selection process, the Company held community informational meetings in Bellingham and initiated a hotline for public comment which it publicized through press releases and advertisements (id. at 47 to 50).

With respect to land use compatibility, Mr. Goulart argued that the question of compatible land use is not a function of zoning, and asserted that the Company scored sites at least in part on the basis of zoning rather than on the basis of the rankings for the land use criterion as defined.[70]

The Bellingham Conservation Commission contended that the Company applied its site selection criteria inconsistently for the evaluated sites with regard to potential noise impacts of the proposed project, location of the proposed project relative to groundwater resources, and potential impacts of interconnecting the proposed project to a natural gas pipeline (BCC Brief at 2 to 3).

The Town of Franklin argued that, because the Company failed to consider the position of residents of Franklin in evaluating community support, the criterion "community support" measured support for "obtaining the necessary permits, waivers and contracts from the Town of Bellingham, rather than ... true community support" (Town of Franklin Brief at 16). In addition, the Town of Franklin argued that the Company "knowingly used incorrect data to further its own pecuniary interest" in scoring the sites considered in its site selection process and "has made no effort to correct the scores that it is relying on to establish the superiority of the Proposed Site" (id. at 17).[71] The Town of Franklin also contended that in the Company's view the basic differences between the proposed Bellingham site and the second-highest scored Bellingham site are not environmental, but related to zoning

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70 In support of his contention that the Company couched its comparison of land use in terms of zoning, Mr. Goulart quoted from the Company's descriptions of two sites, the proposed and Bellingham 4 (Goulart Brief at 4 to 5). The Siting Board notes, however, that the selected quotes are excerpted from the Company's analysis of land use impacts of the proposed facility, in which land use and zoning impacts are treated together, rather than from the Company's discussion of its site selection process.

71 The Town of Franklin argued, for example, that the proposed site inappropriately received an additional 12 points (derivation: weight of 6 on a scale of 1-10 multiplied by the rank of 2 on a scale of 0-2) for the "water availability" criterion (Town of Franklin Brief at 11). The Town of Franklin argued that water availability, based on the proximity of evaluated sites to such major water sources as aquifers, rivers and wastewater treatment facilities, was irrelevant after the Company arranged to purchase water from the Town of Bellingham's municipal water system (id.).

designation and the preference of the Town of Bellingham, and that this perspective undervalued important environmental differences between the two sites (id.).

b. Analysis

In this case, the Siting Board uses a modified scope for reviewing a generation facility applicant's process to select a site for its proposed facility, waiving the requirement that applicants identify two or more sites to be noticed for purposes of the review.[72] Under the modified scope, the Siting Board's review focuses on the selection of a single noticed site from top-ranked sites, including sites in the last stage of the Company's site selection process, as well as on sites which ranked high among the Company's second tier of sites.

While the Company was not required to identify and notice a preferred and alternative site for its proposed facility, the Siting Board's precedent with respect to the development and application of site selection criteria for generating facilities remains applicable. Here, the Company has developed a broad array of criteria which address the critical issues associated with the siting of generating facilities and which are generally consistent with site selection criteria which the Siting Board has found to be appropriate in previous reviews. Millennium Power Decision, EFSB 96-4, at 101; Berkshire Power Decision, 4 DOMSB at 349-351; Cabot Decision, 2 DOMSB at 380-381.

The intervenors have questioned whether the Company applied its site selection criteria consistently to the proposed site and to other sites in its site selection process, including a second Bellingham site, Bellingham 4.[73] The intervenors' concerns focus

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72 In past reviews of cogeneration facilities, including Altresco-Pittsfield, Inc., 17 DOMSC, MASSPOWER, 20 DOMSC, West Lynn Cogeneration, 22 DOMSC, Eastern Energy Corporation, 22 DOMSC, Altresco Lynn Decision, 2 DOMSB, and Cabot Decision, 2 DOMSB, the Siting Board has previously reviewed power plant cases without noticed alternatives.

73 Until the elimination in this proceeding of the requirement for a noticed alternative site, Bellingham 4 was identified by the Company as the noticed alternative to the proposed site.

specifically on the rating of the proposed site and Bellingham 4 with respect to water availability, gas interconnect impacts, land use compatibility and community support.

With respect to ranking of the proposed site above other sites based on on-site water availability, the proposed project as now designed will draw its water supply from the local municipal water system. Viewed in the context of the current design, this criterion is unlikely to distinguish the proposed site from most considered sites, including sites in the Town of Bellingham.

The Siting Board agrees that on-site water availability represents a reasonable factor to include at the screening level, when the water supply requirements and water supply sources of the proposed project might be generally but not finally determined. However, the availability of water from various sources, including public water supplies, wastewater reuse and direct withdrawals from wells or other sources, should be reflected in a Company's water availability criteria. The importance of on-site water availability likely was overstated in the Company's analysis. By way of counterweight, however, the Siting Board notes that other water-resource related criteria, in particular the "proximity to groundwater resources" and "proximity to wetland/floodplain resources" criteria, serve to disadvantage the proposed site relative to some other top-ranked sites, including the Bellingham 4 site, and are given substantial weight. These criteria may also be overstated since the proposed facility footprint can be placed to minimize or avoid groundwater and wetland/floodplain resources.

With respect to gas interconnect impacts, the Company assigns its proposed site a medium rating, although the one-mile proposed gas interconnect slightly exceeds the threshold which would seemingly qualify the site for a low rating on this criterion. As an additional factor supporting a lower rating, there is the possibility that an open-trench crossing of the Charles River, with attendant impacts to the river and adjacent wetlands, could be necessary to construct a gas interconnect to the proposed site. While the Company has indicated its commitment to directional drilling for the river crossing, the final decision as to how the gas interconnect to the proposed site would be installed across the Charles River rests with the company installing the gas pipeline and with FERC (see Section III.B.2.b).

With respect to land use, the Siting Board notes that the Company's site selection process includes separate criteria for land use compatibility and compatibility with zoning, with land use compatibility given more weight than compatibility with zoning. With respect to site scoring on land use compatibility, the intervenors argue that the Bellingham 4 site is preferable to the proposed site because Bellingham 4 abuts an industrial area on one side; however, the Company counters that the proposed site abuts Interstate 495 on one side. Although the potential existed for confusion in the application of the two criteria, the record does not support a conclusion that the Company failed to consider adequately the land use compatibility advantages of the Bellingham 4 site.

Finally, with respect to community support, the Siting Board recognizes that communities neighboring a municipality where a generating project is proposed may reasonably expect attention to concerns they may have with respect to the impacts of the proposed project on the resources of their own city or town. For this reason, municipalities adjacent to communities where projects have been proposed have in the past, as well as in the instant proceeding, been allowed to intervene before the Siting Board. However, these specific concerns are reflected in a proponent's evaluation of criteria such as water and wastewater disposal availability, dispersion environment, proximity to sensitive receptors, and land use compatibility.

The "community support" criterion serves a different purpose. A developer's evaluation of community support is in large part a practical assessment of the developer's ability to work constructively with municipal officials and residents to obtain necessary permits, negotiate mutually agreeable financial arrangements, resolve concerns regarding the impacts of the project, and bring the project to a successful conclusion. No responsible developer would proceed with a generating facility project without such an assessment. When viewed in this light, it is clear that "community support" should primarily measure support within the community in which the project is proposed. The initial decision to allow the construction of a facility such as a power plant is the prerogative of the municipality where the facility is to be located. Thus the Company's use of the community support criterion to measure support from the municipality where a considered site is located, rather than the support of that and surrounding municipalities, is reasonable.

The Siting Board has held that an applicant is best informed about community support if its site selection analysis includes an assessment of support from residents as well as from municipal officials. Here, the Company included a measure of "community support" based primarily on contact with local officials and historical public reaction to industrial development. The Siting Board notes that discussions of the specific proposed project with potential residential, commercial and industrial neighbors may alert the developer to important site specific issues that could affect the Siting Board's analysis of the cost or environmental impacts of the proposed project at a potential site. The Siting Board acknowledges that it is also possible to identify many such issues by screening potential sites based on surrounding land uses and proximity to sensitive receptors, as ANP has done. In the instant proceeding, the developer has also conducted public outreach earlier than developers in other generation facility cases recently before the Siting Board. The Siting Board notes that if outreach is not incorporated into early stages of project development, new, potentially serious concerns requiring additional mitigation or even selection of a different site may be raised.

The Siting Board has expressed varying degrees of concern regarding the Company's evaluation of three screening criteria: water availability, gas interconnect impacts, and community support. A retrospective reevaluation of the water availability and gas interconnect criteria might marginally lower the score of the proposed site relative to other sites considered by the Company. Similarly, we have noted that a retrospective reevaluation of two other criteria, "proximity to groundwater resources" and "proximity to wetland/floodplain resources", might marginally increase the relative score of the proposed site.

The Siting Board recognizes that a numerical screening analysis is only the starting point of the site selection process. As evidenced here, a sound screening process may identify a number of sites which receive similar high scores but which have different strengths and weaknesses, so that no one site is clearly superior to the others. For example, in the instant proceeding, the record indicates that the proposed site is superior to Bellingham 4 with respect to community support, zoning, and the potential for site contamination, whereas the Bellingham 4 site is preferable with respect to the gas interconnect, road and rail infrastructure, and groundwater resources. Overall, the record indicates that the proposed site, the Bellingham 4 site, and the other high-ranking sites considered by the Company have different but offsetting strengths and weaknesses as sites for the proposed generating facility.

Accordingly, the Siting Board finds that the Company did not overlook or eliminate a clearly superior site for its project.

Based on an analysis of the preliminary phases, quantitative (screening level) phase and final qualitative phases of the Company's site selection process, the Siting Board finds that (1) the Company has developed a reasonable set of criteria for identifying and evaluating alternative sites, and (2) the Company has appropriately applied a reasonable set of criteria for identifying and evaluating alternative sites in a manner that ensures that it has not overlooked or eliminated any clearly superior site.

c. Geographic Diversity

In this section, the Siting Board considers whether the Company's site selection process included consideration of site alternatives with some measure of geographic diversity. The Siting Board notes that with the modification of its site selection review in this proceeding, the Siting Board's previous requirement that an applicant must provide at least one noticed alternative with some measure of geographic diversity is moot.

The Company asserted that it has identified at least two sites with some measure of geographic diversity (Exh. BEL-1, at 5-16). The Siting Board notes that there is no minimum distance that is sufficient to establish geographic diversity in any given case. The Siting Board previously has determined that two sites in the same town can provide adequate geographic diversity for a generating facility review. Millennium Power Decision, EFSB 96-4, at 105; Berkshire Power Decision, 4 DOMSB at 357; NEA Decision, 16 DOMSC at 385-388. Further, in a transmission line case, the Siting Council stated that simple quantitative diversity thresholds were not appropriate for evaluating geographic diversity. New England Power Company, 21 DOMSC 325, 393 (1991). Here, among its ten top-ranked sites the Company has provided sites with varying environmental characteristics in seven different communities.

Accordingly, the Siting Board finds that the Company has identified at least two practical sites with a sufficient measure of geographic diversity.

3. Conclusions on the Site Selection Process

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

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

B. Environmental Impacts of the Proposed Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents in a case without a noticed alternative site to show that proposed facilities are sited a location that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed site is superior to alternatives on the basis of balancing cost, environmental impact and reliability of supply. See Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; Berkshire Gas Company, 23 DOMSC 294, 324 (1991). Specifically, in accordance with the Scope of Review set forth in Section I.D, above, the applicant must show that its proposed facility is sited, designed and mitigated in a manner that will minimize cost and environmental impacts, and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability.

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; EEC Decision, 22 DOMSC 188, 334, 336 (1991). A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; EEC Decision, 22 DOMSC at 334, 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276-277; EEC Decision, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 277; EEC Decision, 22 DOMSC at 334, 336. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in specific facility proposals. Berkshire Power Decision, 4 DOMSB at 358-359; Silver City Decision, 3 DOMSB at 277; EEC Decision, 22 DOMSC at 334, 335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular review must be clearly described and consistently applied, to the extent practicable, from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[74] Berkshire Power Decision,

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[74] The Siting Board notes that project proponents are required to submit to the Siting Board a description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of (continued...)

4 DOMSB at 359; Silver City Decision, 3 DOMSB at 277; 1993 BECo Decision, 1 DOMSB at 39-40, 154-155, 197. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. Berkshire Power Decision, 4 DOMSB at 359; Silver City Decision, 3 DOMSB at 278; 1993 BECo Decision, 1 DOMSB at 40.

Accordingly, in the sections below, the Siting Board examines the environmental impacts of the proposed facilities at the proposed site to determine whether the Company's proposal minimizes specific sets of environmental impacts. The Siting Board then examines the cost of the proposed facility, including costs of further mitigation, in order to determine whether an appropriate balance would be achieved among conflicting environmental concerns and among environmental impacts, costs and reliability.

2. Environmental Impacts

a. Air Quality

(1) Applicable Regulations

The Company indicated that regulations governing air impacts of the proposed facility include National Ambient Air Quality Standards ("NAAQS") and Massachusetts Ambient Air Quality Standards ("MAAQS");[75] Prevention of Significant Deterioration ("PSD") requirements; New Source Review ("NSR") requirements; and New Source Performance Standards ("NSPS") for criteria pollutants (Exh. BEL-1, at 6-2). In addition, the Company

[74](...continued)
a generating facility provide a description of the primary and alternative sites and the surrounding areas in terms of: natural features, including, among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impacts of the facility in terms of its effect on the natural resources described above, land use, visibility, air quality, solid waste, noise, and socioeconomics. 980 C.M.R. § 7.04(8)(e).

[75] The MDEP has adopted the NAAQS limits as MAAQS.

indicated that the proposed facility would fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. HO-EA-4.1, at 3-4).[76] Finally, the Company stated that the Secretary of Environmental Affairs had ordered that the environmental impact report ("EIR") for the proposed facility "must consider the cumulative impacts of this facility combined with other generators within a predetermined radius"[77] (Exh. BEL-15, Vol. II, at App. A).

The Company indicated that, under NAAQS, all geographic areas are classified and designated as attainment, non-attainment or unclassified for the six criteria pollutants: SO_2, PM-10, NOx, CO, ground level ozone ("O_3") and lead ("Pb") (Exh. BEL-1, at 6-3). The Company further indicated that, although the Bellingham area is classified as "attainment" or "unclassified" for SO_2, PM-10, NOx, CO, and Pb, the entire Commonwealth of Massachusetts is in "serious" non-attainment for O_3 (id. at 6-4).

The Company stated that under PSD requirements, the proposed facility must (1) demonstrate compliance with NAAQS, and (2) apply Best Available Control Technology ("BACT") to emissions of NOx, CO, and PM-10, pollutants for which emissions may potentially exceed 100 tpy (Exhs. HO-EA-4.1, at 4-6; BEL-13.2, at 4-1).

The Company further indicated that under NSR requirements, the proposed facility must apply Lowest Achievable Emission Rate ("LAER") technology and emissions offsets to any directly emitted pollutant which is a precursor to O_3, and which the proposed facility may emit at levels greater than 50 tpy (Exhs. HO-EA-4.1, at 4-1, 4-12; BEL-13.2, at 4-1). Thus,

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76 The Company stated that to comply with Title IV Sulfur Dioxide Allowances and Monitoring regulations, it will be required to obtain SO_2 allowances each year in an amount equal to the potential number of tons of SO_2 to be emitted (Exh. HO-EA-4.1, at 3-4). The Company stated that SO_2 allowances would be available through the Chicago Board of Trade, and would be obtained for the project prior to the commencement of operations (id.).

77 The Secretary's certificate on the Environmental Notification Form ("ENF") for the proposed project required the proponent to conduct a cumulative impacts analysis to ensure that environmental impacts from this facility and others in the local geographic area, both existing and proposed, are adequately considered as part of the Final Environmental Impact Report ("FEIR") for the project.

the Company must apply LAER technology to control NOx (id.). With regard to NSPS requirements, the Company indicated that emissions of regulated pollutants -- NOx and SO_2 -- would fall well below NSPS threshold levels (Exh. HO-EA-4.1, at 3-4).

In addition, the Company noted that the proposed facility would incorporate BACT for SO_2 and VOCs as well as for other non-criteria pollutants and air toxics that are regulated as part of the MDEP air plans approval process (id. at 4-6; Exh. BEL-1 at 6-6).

(2) Emissions and Impacts

(a) Description

The Company indicated that the proposed facility would emit regulated pollutants, including criteria and non-criteria pollutants, and CO_2 (Exhs. HO-EA-4.1, at 3-2, 4-1; BEL-13.2, at 3-1, 4-1). The Company asserted, however, that air quality impacts from the proposed facility would be minimized through the use of natural gas as fuel, efficient combustion technology, advanced pollution control equipment, and acquisition of NOx offsets (Exh. BEL-1, at 6-2, 6-17). The Company also asserted that dispatch of the proposed project in preference to older generating resources in the region would result in displacement of NOx, SO_2 and CO_2 emissions (id. at 6-20).

The Company stated that its proposed facility would incorporate BACT for CO, PM-10, SO_2, Pb, and VOCs as well as both BACT and LAER for NOx (id. at 6-6). The Company further stated that emission rates for non-criteria pollutants would represent BACT for each substance. In support of its contention that the proposed facility would represent BACT and/or LAER for the identified pollutants, the Company provided information regarding control options for the proposed facility (Exh. HO-EA-4.1, at 4-1 to 4-11).

The Company estimated the quantity of pollutants that would be emitted from the proposed facility on the basis of information from manufacturers and vendors of plant equipment and from government data centers (Exhs. BEL-1, at 6-16; HO-EA-4.1, at 3-1, 4-2). The Company provided calculations of air emissions for the proposed facility based on the identification of "worst-case" operating conditions, which the Company stated would be

100 percent load, with steam augmentation, at an ambient temperature of 90 degrees Fahrenheit[78] (Exh. BEL-13.2, at 5-1).

The Company asserted that predicted concentrations of air pollutants to be emitted by the proposed facility would be "insignificant" relative to applicable ambient air quality standards (Exhs. BEL-1, at 6-2, HO-EA-4.1, at 5-12; BEL-13.2, at 5-1). In support of its assertion, the Company provided results of local air quality modelling, which indicate that the air quality impacts of the proposed facility on ambient concentrations of criteria pollutants would be below established significant impact levels ("SILs") assuming the proposed Good Engineering Practice ("GEP") stack height of 180 feet[79] (Exhs. HO-EA-4.1, at 5-2; BEL-13.2, at 4-1).

The Town of Franklin expressed concern that lands within its borders would suffer from the deposition of particulate emissions originating at the proposed facility (Franklin Brief at 3). In response, the Company prepared a particulate deposition analysis using the EPA-approved ISC model which demonstrated that although the maximum predicted annual deposition rate was projected to be three kilometers southeast of the site -- a location clearly within the Town of Franklin -- deposition of particulates from the project would nonetheless represent an insignificant fraction of ongoing deposition from existing sources and background concentrations (id.; Tr. 7, at 85-92; Exh. F-RR-2).

With respect to emissions of non-criteria pollutants and air toxics, the Company stated that SCREEN3 modelling was conducted to estimate emissions of formaldehyde, sulfuric acid, and ammonia. The Company then compared the predicted concentrations of these

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78 The Company indicated that its worst-case operating condition would result in maximum emissions of NOx, SO_2, and PM-10. The Company stated that the worst-case operating condition for CO would be 50 percent load at 90 degrees Fahrenheit (Exh. BEL 13.2, at 5-1).

79 The Company stated that it used the USEPA SCREEN3 model to conduct screening-level modelling for a range of operating conditions. The Company stated that by varying load, ambient temperature, and the application of steam augmentation, worst-case impacts could be identified and compared to applicable SILs and ambient air quality standards (Exh. HO-EA-4.1, at 5-6).

pollutants to the applicable MDEP standards[80] (Exhs. HO-EA-4.1, at 5-12; BEL-13.2, at 5-3). The Company stated that the resulting concentrations were predicted to be below SILs for all pollutants except formaldehyde.[81]

The Company performed additional, more refined modelling -- using the EPA recommended ISCST3 which incorporates hourly meteorological data -- to further evaluate the operating scenario for which the concentration of formaldehyde was found, based on screening level modelling, to be above the SIL. The Company stated that its refined modelling comprised a 24 square kilometer receptor grid surrounding the facility site, and incorporated elevation data for all significant terrain features within that area (Exh. HO-EA-4.1, at 5-13). The Company further stated that it used five years (1990 to 1994) of actual meteorological observations as inputs to the model, and indicated that the data was recorded at Worcester Airport and Bradley Field (surface data), and at Albany, New York (mixing height data) (id.). Based on its refined modelling, the Company stated that formaldehyde concentrations were predicted to be below the applicable TELs and AALs for the identified maximum impact load condition (id. at 5-21).

With respect to impacts to sensitive vegetation and soils, the Company asserted, citing supporting documentation and modelling results, that its proposed facility would have no negative impacts on sensitive vegetation or soils (Exh. BEL-1, at 6-23).

The Company asserted that operation of the proposed facility would cause economic displacement of older, higher emitting units and would therefore be expected to result in regional air quality benefits (Exh. BEL-15, at 7-1). In support of its assertion, the Company presented a displacement analysis for the five year period 2000 to 2004, indicating that regional emissions of the criteria pollutants SO_2, NOx, and CO_2 would be significantly reduced with dispatch of the proposed facility. For the two criteria pollutants SO_2 and NOx,

80 The applicable standards are MDEP Threshold Effects Exposure Limits ("TELs"), and annual average Allowable Ambient Limits ("AALs") (Exh. HO-EA-4.1, at 5-12 and 5-21).

81 The Company's screening analysis indicated that formaldehyde concentrations were predicted to exceed the SIL under the operating condition of 50 percent load, at an ambient temperature of 90 degrees Fahrenheit (Exh. HO-EA-4.1, at 5-12).

the five-year reductions would be several times larger than the proposed facility's own emissions over the same period (id. at 6-20; Exhs. HO-N-25; HO-RR-20.10) (see Section II.A.4, above). The Company stated that the net emissions reductions attributable to the proposed facility would be expected to provide benefits with respect to two areas of environmental concern -- acid precipitation and ground-level ozone (Exh. BEL-1, at 3-21).

With respect to the analysis of cumulative impacts as ordered by the Secretary of Environmental Affairs, the Company stated that it had prepared a cumulative air impacts analysis as part of the DEIR filed in docket EFSB 97-2, for the proposed ANP-Blackstone Energy Project.[82] The Company indicated that the analysis addressed the two projects currently proposed by ANP, and a generation project proposed for a site within the Town of Bellingham by IDC in docket EFSB 97-5. Additionally, the analysis considered other major sources in the region that met the following criteria: (1) sources within ten kilometers of the proposed facility with the potential to emit 50 tpy or more of NOx, 100 tpy or more of SO_2, or 100 tpy or more of CO, and (2) sources within 20 kilometers of the proposed facility with the potential to emit 1,000 tpy or more of NOx, SO_2, PM, or CO (Exh. BEL-13.2, at App. C). The Company stated that based on the above criteria, its interactive source model included three proposed and nine existing sources.[83]

82 The Company indicated that the Secretary of Environmental Affairs had initially required a cumulative impacts study in connection with the ANP-Blackstone Project, and that MDEP had subsequently requested that the study also be included as part of the Air Plans Application for the proposed facility (Tr. 7, at 79-80) (see Exh. BEL-13.2).

83 The Company stated that the criteria for selecting among existing sources was developed by MDEP. The existing sources examined were, Bellingham Cogen, Bellingham CO_2, Milford Power, Ball Foster, Boston Edison-Medway (six units), Boston Edison-Framingham (three units), Milford High School, OSP (two units), and Woonsocket Waste Water Treatment Facility. The Company noted that two of the nine existing sources included in the model are located in the state of Rhode Island, and indicated that it identified these sources as a result of discussions with the Rhode Island Department of Environmental Management (Exh. BEL-13.2, at App.C).

The Company stated that it used the ISCST3 model with the same model inputs and meteorology as for its refined analysis conducted for the proposed ANP Blackstone project[84] (id.). The Company stated that results of the interactive modelling demonstrated that the maximum combined concentrations of criteria pollutants from both the existing and proposed sources, plus existing background levels, would be within MAAQS and NAAQS (id. at 8-23). The Company further indicated that it conducted modeling of two subgroups of proposed and existing sources: (1) the three currently-proposed generating projects, and (2) the three proposed projects plus three existing generating facilities -- Bellingham Cogen (formerly Northeast Energy Associates), and the Milford Power and OSP projects. The Company stated that the results of the analysis showed that the contribution of these subgroups to ambient concentrations would be small as compared to MAAQS and NAAQS (id.).

(b) Analysis

The Company has demonstrated that emissions of criteria and other pollutants from the proposed facility at the proposed site would have acceptable impacts on existing air quality. The record shows that the proposed facility would include two highly-efficient combustion turbines with natural gas as the sole fuel. Additionally, the Company has indicated that the proposed facility would incorporate advanced emissions control technologies.

The Company has used reasonable and appropriate air modelling techniques to assess the impacts of emissions from the proposed facility, and has demonstrated that impacts from the proposed facility would be below SILs for all criteria emissions and for other hazardous or toxic air pollutants.

With respect to the modelling of cumulative air quality impacts from the proposed facility and other existing and proposed sources in the region, the Company has provided an analysis, using MDEP-approved protocols, which demonstrates that cumulative air impacts are projected to be within the applicable MAAQS and NAAQS for all criteria pollutants. Moreover, the analysis demonstrates that existing air quality is well within the ambient air

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84 The Siting Board notes that refined ISCST3 modelling for the proposed ANP Blackstone facility was conducted for the criteria pollutants SO_2, NO_2, and PM-10.

quality standards and that emissions from the proposed facility would represent a small fraction of those standards. The Siting Board notes that the interactive source model presented in this case initially was developed at the request of the Secretary of Environmental Affairs in docket ANP Blackstone Energy Company, EFSB 97-2, and recognizes that its inclusion in the record in this case is appropriate.

(3) Offset Proposals

(a) Description

The Company indicated that, to comply with non-attainment NSR for NOx, it would obtain NOx offsets at a minimum ratio of 1.2 to 1.0 (Exh. HO-EA-4.1, at 4-12). The Company stated that, in Massachusetts, offsets are generated by obtaining MDEP-certified Emission Reduction Credits ("ERCs") in an amount that is five percent greater than that required based on the 1.2 to 1.0 ratio, i.e., a total ERC requirement of 1.26 times maximum facility NOx emissions (id.). The Company stated that, based on the expected facility NOx emissions of 222 tpy, the proposed facility would require offsets for 280 tons of NOx per year (id.). The Company stated that it had identified potential sources of NOx offsets, primarily resulting from in-state shutdown credits (Tr. 7, at 18).[85]

The Company indicated that the proposed facility would emit a maximum of 1,948,500 tpy of CO_2 and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. BEL-1 at 6-19 to 6-20; HO-EC-1). In researching possible CO_2 mitigation strategies for the proposed facility, the Company stated that it had requested proposals from three organizations; (1) the Conservation Law Foundation, (2) the Charles River Watershed Association ("CRWA"), and (3) the New England Forestry Foundation, all regarding projects that would result in effective CO_2

[85] The Company stated that in order for the proposed project to receive an MDEP permit to construct, it would be required to identify the expected source(s) of NOx offsets for the proposed facility, and provide evidence that it had contracted for, or held options on, certified or readily certifiable offsets in the full amount required for the project (Tr. 7, at 22-23). Other potential sources of NOx offsets identified by the Company included additional in-state credits (i.e., surplus ERCs), and the future potential for interstate trading (id. at 18; Exh. HO-EA-4.1, at 4-12).

mitigation for the proposed facility (Tr. 7, at 49-50). The Company indicated that it had not yet received any detailed proposals from these entities, but that it would continue to investigate options for CO_2 mitigation (id.; Exh. HO-RR-36).

The Company further argued that the operation and dispatch of the proposed facility over the period 2000 to 2004 would result in the displacement of CO_2 emissions from other facilities, and would contribute to the minimization of CO_2 impacts from the project (Exh. BEL-1, at 6-20). In support of its argument that the proposed facility would displace CO_2 emissions from other facilities the Company provided a displacement analysis for the identified five-year period (Exhs. HO-N-25; HO-RR-20.10). The analysis showed a five-year reduction in regional CO_2 emissions of 7,030,000 tons, or 85 percent of the proposed facility's 8,314,000 tons of CO_2 emissions over the same period (Exhs. HO-N-25; HO-RR-20.10).

Finally, the Company considered the impact of its proposed on-site tree clearing on annual CO_2 assimilation. The Company asserted that, in terms of CO_2 impacts, the effect of the proposed tree clearing would be insignificant as compared to stack emissions, and estimated that lost assimilation capacity as a result of clearing 26 acres of trees would equate to approximately 100 tpy of CO_2 (Exhs. HO-RR-37; Tr. 7, at 51-52).[86]

(b) Analysis

The Company has presented analyses for NOx and CO_2 -- pollutants which potentially contribute to regional ground-level ozone concerns and international climate change concerns, respectively. With respect to NOx, the Company has established that it has a viable plan in place to obtain NOx ERCs consistent with non-attainment NSR and MDEP requirements.

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86 Mr. Sellars stated that the Company's estimate was based on an annual assimilation rate of 7,700 pounds of CO_2 per acre of forested land. The Company indicated that this information was derived from a document entitled "Sector Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605 (b) of the Energy Policy Act of 1992, Vol. 2" (Exh. HO-RR-37).

In the Dighton Power Decision, the Siting Board set forth a new approach to the mitigation of CO_2 emissions that required generating facilities to make a monetary contribution, within the early years of facility operation, to one or more cost-effective CO_2 offset programs, with such program(s) to be selected in consultation with the Siting Board Staff. EFSB 96-3, at 42-43.[87] In Dighton, the Siting Board expressed an expectation that the contributions of future project developers would reflect that set forth in Dighton, which was based on an offset of one percent of annual facility CO_2 emissions, at $1.50 per ton, to be donated in the early years of facility operation. Id. at 43.

Here, the Company has proposed to contribute an amount, based on the proposed facility's annual maximum CO_2 emissions over 20 years of operation, that would be consistent with those ordered in recent generating facility cases. Based on projected maximum annual CO_2 emissions of 1,948,500 tpy for the proposed facility, the total contribution requirement would be $584,550. In a past case, the Siting Board allowed for payment of the contribution amount over five years, or alternatively as a first-year equivalent value, calculated by summing the five annual increments, and then discounting the stream of contributions to reflect constant first-year dollars. Dighton Power Decision, EFSB 96-3, at 40-44. In a more recent case, a similar methodology was used to calculate the appropriate first-year contribution, although in that instance, the Siting Board first escalated the five annual increments to reflect a potential for increased cost in future years to achieve the targeted offset levels. Millennium Power Decision, EFSB 96-4, at 114, 117-118. Therefore, consistent with the CO_2 mitigation requirement set forth in the Millennium Power Decision, the Siting Board requires the Company to provide CO_2 offsets through a total contribution of $620,690 to be paid in five annual installments[88] during the first five years of facility operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation

87 Previously, the Siting Board required project proponents to commit to a specific program of CO_2 mitigation, such as a tree planting or forestation program, designed to offset a percentage of facility CO_2 emissions within the early years of facility operation. See Berkshire Power Decision, 4 DOMSB at 373-374.

88 Annual contribution amounts would be distributed as follows: year one $116,910; year two $120,417; year three $124,030; year four $127,751; year five $131,583.

with the Staff of the Siting Board. Alternatively, the Company may elect to provide the entire contribution within the first year of facility operation. If the Company so chooses, the CO_2 offset requirement would be satisfied by a first-year contribution in the amount of $467,940 to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board.[89] With respect to the impact of tree clearing on CO_2, the record indicates that 26 acres of trees would be removed to accommodate the facility footprint, and the Company has stated that such acreage represents an estimated CO_2 sequestration capacity of 100 tpy, or roughly four tpy of CO_2 per acre. The record does not contain additional information on the assumptions used to arrive at the identified annual assimilation rate. Specifically, the record does not specify operative assumptions as to the relative age of forest growth or the types of species present, i.e., primarily coniferous versus primarily deciduous -- factors likely to be significant in determining the actual CO_2 sequestration rate.

In a number of past reviews, developers of generating facilities have proposed offsetting facility CO_2 emissions through contributions to MASS Releaf, a state program which plants shade trees throughout the commonwealth. Altresco Lynn Decision, 2 DOMSB at 183-186, 217-220; Eastern Energy Corporation Decision on Compliance, 25 DOMSC at 349. In those cases, it was assumed that each tree planted would sequester 30 tons of CO_2 over a 40-year period of analysis, yielding an annual average of 3/4 tpy of CO_2 per tree.[90] Altresco Lynn Decision, 2 DOMSB at 219; Eastern Energy Corporation Decision on Compliance, 25 DOMSC at 350, fn. 67. To ensure consistency between cases in establishing required offset levels, the Siting Board determined that it was appropriate to

89 The identified amount of the first-year contribution is the NPV of the 20-year amount of $584,550, first distributed as a series of payments to be made over the first five years of facility operation, then adjusted to include an annual cost increase of three percent. The $620,690 sum of those five annual contributions is then discounted (at ten percent) back to the first year, yielding $467,940. Note: Figures rounded to the nearest ten dollars.

90 In Eastern Energy Corporation, the estimated cost CO_2 offsets through participation in MASS Releaf was $3.33 per ton. Id. at 350.

adjust required tree planting to reflect case-by-case differences in on-site tree clearing required for project development. Altresco Lynn Decision, 2 DOMSB at 219. Based on sequestration levels assumed for tree planting under the MASS Releaf program, the Siting Board accepted adjustment allowances of as high as 225 tpy per acre of cleared trees. Id. Thus these adjustments for on-site tree clearing were as much as 50 times or more the allowance of 4 tpy per acre proposed by ANP-Bellingham.

The Siting Board recognizes that the application in past reviews of tree-clearing adjustment allowances based on sequestration rates assumed for planted urban shade trees may have resulted in some overstating of the adjustment allowances. At the same time, the Company has not adequately supported its proposed adjustment allowance, and the Siting Board is concerned that it may understate the adjustment that would be appropriate for the clearing of woodlands at the proposed site. Therefore, the Siting Board will determine an adjustment allowance for the proposed tree clearing based on balanced consideration of the record and available precedent. For purposes of this review, the Siting Board assumes that a sequestration rate of 30 tpy of CO_2 per acre, applied over a 30 year period, provides a reasonable basis to estimate the CO_2 sequestration that would be lost as a result of clearing the proposed site.[91] Thus the allowance for clearing 26 acres would be 23,400 tons of CO_2. At $1.50 per ton, this yields an additional first year offset contribution of $35,100 to the CO_2 offset program or programs selected to offset facility emissions.

Accordingly, the Siting Board finds that, with implementation of the foregoing NOx and CO_2 offset measures, the environmental impacts of the proposed facility at the proposed site would be minimized with respect to air quality.

[91] The figure of 30 tpy per acre is roughly the multiplicative mean between the Company's proposed rate of 4 tpy per acre and the Siting Board precedent of 225 tpy per acre. The Siting Board assumes a 30-year period as representative of the average age of trees in the on-site woodlands.

b. Water-Related Impacts

(1) Impacts

In this section, the Siting Board addresses the water-related impacts of the proposed facility, including: (1) the water supply requirements of the facility and related impacts on affected water supply systems and on wetlands and other water resources; (2) the water-related discharges from the facility, including wastewater discharges and discharges from on-site stormwater management facilities, and related impacts on wastewater systems and on wetlands and other water resources; and (3) the construction impacts of the proposed facility and associated interconnection facilities on wetlands and other water resources.

The Company provided estimates of water supply needs for the proposed facility for two possible operating designs or scenarios: (1) baseload operations of 545 MW, without steam augmentation; and (2) use of steam augmentation to generate an additional 40 MW for 10 percent of the year, 12 percent of the year or 20 percent of the year (Tr. 10, at 63, 124 to 163; Tr. 11, at 50 to 54).[92] The Company stated that it expected to use steam augmentation 10 percent, or approximately 37 days of each year, but indicated that it had contracted for sufficient water to use steam augmentation for up to 20 percent or 73 days of the year (Tr. 11, at 52). Differences in the Company's water supply estimates correlated to differences in the number of days of steam augmentation.

The Company stated that the proposed project would incorporate air cooled condensers in order to minimize water requirements to the maximum extent possible (Exh. BEL-1).

The Company indicated that baseload water supply needs for the proposed facility, including potable water supply, would be approximately 14,000 gallons per day ("gpd") or 4.2 million gallons per year ("mgy"), based on 302.2 days of operation annually (Tr. 10,

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92 The Company variously estimates the baseload output of the proposed facility at 535 and 545 MW, and the output from steam augmentation at 35 and 40 MW (Exh. BEL-1, at 1-5 to 1-6, 3-2; Tr. 10, at 63). With respect to water supply needs, baseload output of 545 MW and additional output from steam augmentation of 40 MW are the more conservative estimates, and are therefore the basis for the discussion and analysis in this section.

at 129, 131).[93] The Company also indicated that steam augmentation would increase the average daily water requirement of the proposed facility (Tr. 11, at 50 to 54). The Company provided estimates for water requirements above baseload water supply for its three scenarios incorporating steam augmentation (id.). These ranged from an additional 25 mgy with 37 days of steam augmentation to an additional 50 mgy with 73 days of steam augmentation based on 302.2 days of plant operation annually (id.). The Company estimated the combined baseload and steam augmentation water supply requirements for the proposed facility at 29.2 mgy (on average 96,600 gpd for 302.2 days) for 37 days of steam augmentation and 54.2 mgy (on average 179,000 gpd for 302.2 days) for 73 days of steam augmentation (id.).

The Company indicated that water use for the proposed facility might in theory be as much as 684,000 gpd based on its vendor's estimate that steam augmentation would require 28,500 gallons of water per hour (Exh. HO-EW-8). The Company explained, however, that because use of steam augmentation would correspond to periods of peak power production -- approximately seven to eight hours per day -- daily water use likely would be much less than the theoretical maximum (Exhs. HO-EW-7; HO-EW-8).

The Company stated that its water supply would come primarily from Town of Bellingham municipal water supplies (Exh. BEL-1, at 6-31). The Company provided a copy of its Agreement for Water and Sewer Services ("Agreement") with the Town of Bellingham (Exh. HO-V-7.1). The Agreement states, in part, that the Company has the right to withdraw water from Bellingham's municipal water supply in quantities up to 100,000 gpd during the period March 15 through November 15, and up to 250,000 gpd during the period November 15 through March 15 (id. at 3).[94] The Company indicated that it would tie into

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93 The Company used 14,000 gpd as an approximate estimate of baseload input for its proposed facility. The Company submitted a water balance diagram which reported baseload input more precisely at 13,400 gpd (Exh. BCC(2)-WW4.1; Tr. 10, at 129).

94 The Company's Agreement with Bellingham also addresses the matter of ANP's payment for its withdrawals of water from the Bellingham municipal water system (Exh. HO-V-7.1). According to the Agreement, ANP will be a customer of the Town's water supply system and will be billed according to the rate structure used for billing all customers of the Town water system for use up to the daily maximum (id.).
(continued...)

the municipal system through a connection extending into the site from an existing Maple Street water line, predominantly 12 inches in diameter (Exh. BEL-1, at 6-31).

The Company stated that for summer steam augmentation purposes, as well as for emergency fire flows, the proposed facility would include a raw water tank, as well as a demineralized water tank (id.). The Company testified that the demineralization tank would hold 1.5 million gallons and the raw water tank would hold one million gallons, of which 700,000 gallons would be available for demineralization and use in the facility and 300,000 gallons would serve as a permanent reservoir for fire-fighting purposes (Tr. 10, at 66). The Company stated that the raw water storage and demineralized storage on site would yield enough water for 3.7 days' operation of the proposed facility in the summer at the maximum rate, i.e., with steam augmentation (id., at 67-68).

The Company indicated that it would fill the demineralized and raw water tanks with the water allocated by the Town to the proposed facility during periods when less than the maximum allowable flows are required and that water volumes taken to fill the tanks thereafter would match the daily water needs of the proposed facility (Exh. BEL-1, at 6-31).

The Company indicated that the water supply for the Town of Bellingham comes from nine municipal wells in two watersheds, the watersheds of the Charles and the Blackstone River basins and their sub-basins (Exhs. EW-1.1; HO-RR-49). The Company asserted that water resources would not be significantly affected by the proposed facility (Exh. BEL-1, at 6-24). In support, the Company provided data for the Town municipal water supply wells ("supply wells") by river basin, including permitted withdrawal volumes, actual average daily use, and total annual use for the years 1993 through 1996 (Exh. HO-RR-49) (see Appendix, Table A-1).[95]

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[94](...continued)
The Agreement also provides that ANP will be billed at a rate of 1.4 times the highest rate block for usage over the daily averages previously noted (250,000 gpd one-third of the year and 100,000 gpd during the remainder of the year) (id.). See Sections III.B.2.b.(2) and III.B.2.b.(3), below.

[95] The Company explained that the Water Management Act sets allowed withdrawals for (continued...)

The Company also provided a comparison of the withdrawal rates of each of the supply wells to groundwater recharge rates for the 1993 through 1996 period (Exh. HO-RR-51). In its comparison, the Company indicated that the estimated volumes of recharge to each supply well are two to four times the amount pumped historically on average (id.). Based on its comparison and analysis, the Company argued that the maximum withdrawals for the proposed facility would not significantly change the relationship between the recharge available to each supply well and the amount the supply wells would be pumping even given maximum water withdrawal under the Company's contract (id.) (see Appendix, Table A-2).

In addition, the Company examined the impact of estimated population growth on water use projections within the Charles and Blackstone River basins for the Town of Bellingham through the year 2020 (Exh. HO-RR-52). The Company relied on several sources for its analysis, including a report of historic and projected water use for the Charles River basin prepared by the Massachusetts Department of Environmental Management ("MA DEM") and a 1997 study by consultants for the Town of Bellingham which modeled the Town's future growth (id.; Exh. EFSB-1). The Company compared projections of population growth against actual water use and future permitted water use from the Charles and Blackstone River basins for the Town of Bellingham under the Massachusetts Water Management Act ("MA WMA") (Exh. HO-RR-52).[96]

The Company indicated that annual average daily water withdrawals in recent years through 1996 were well below the MA WMA permitted water withdrawal for the Town of Bellingham (Exh. HO-RR-52.2). The Company also indicated that through 2010, the years

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[95](...continued)
the supply wells, and that the amounts specified are the sum of a registered volume and a permitted volume: the registered amount is fixed and is based on historical water use in the Town from 1981 to 1985, while the permitted amount is in addition to the registered amount and increases incrementally over four five-year periods (Exh. HO-RR-49).

[96] The Company indicated that while population increased gradually from 14,300 in 1980 to 15,200 in 1995, Town of Bellingham annual average daily water withdrawals fluctuated during the same time frame (Exh. HO-RR-52.2).

for which information was available, the MA DEM projected water use for the Town of Bellingham increased at a rate equal to or less than the rate of permitted water use (id.)

The Company also submitted 7Q10 low flow data[97] and average daily summer (July through September) flow data for four locations, the Millis and Waltham gauging stations in the Charles River Basin and the Woonsocket and Peters Brook gauging stations in the Blackstone River Basin (Exhs. HO-RR-54, HO-RR-54S). The Company stated that the maximum daily water withdrawals during the summer for the proposed facility, 0.10 mgd, would be distributed evenly between the Charles and Blackstone River basins. The Company acknowledged that increased groundwater withdrawals could ultimately affect flow amounts in rivers within the respective basins,[98] but indicated that any such effect would be insignificant relative to the historical flow levels, even during low flow (id.). The Company therefore asserted that associated impacts on the Charles and Blackstone River basins would be acceptable (Exh. HO-RR-54, HO-RR-54S) (see Appendix, Table A-3).

The Company also discussed MA WMA permits issued by MDEP in 1989-1990 and in 1995-1997, authorizing Town of Bellingham well withdrawals from the Charles River

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[97] The 7Q10 flow is, by definition, the lowest daily flow in a river or stream averaged over 7 days that is expected to occur every 10 years.

[98] A 1991 report by the United States Geological Survey, Water Resources and Aquifer Yields in the Charles River Basin, Massachusetts ("USGS Study"), described a modeling analysis of available groundwater yields from 15 major aquifers in the middle and upper Charles River basin (Exh. EFSB-1). As part of the analysis, the USGS Study addressed the extent to which available groundwater yields from such aquifers would be reduced by varying assumptions as to minimum amounts of in-stream flow that are now, or may be in the future, deemed desirable or required for water quality or other environmental purposes (id. at 41, 45). The USGS study indicated that, although large amounts of water potentially are available from major aquifers, additional pumpage would reduce stream flow in the Charles River and its tributaries at some locations (id. at 41). The USGS study assumed that wells in major aquifers by-and-large use groundwater that otherwise would discharge to streams, and thereby provide in-stream flow during dry periods (id.). The USGS study concluded that, if a minimum streamflow requirement were set to ensure that 7Q10 is maintained 95 percent of the time, the ability of wells to use groundwater that otherwise would discharge to streams would be limited to an aggregated aquifer yield of less than one mgd in most of the 15 aquifers, including the Bellingham-Medway aquifer.

basin and Peters Brook subbasin, as well as a 1989 report by MDEM identifying habitat attributes and associated water management issues in Peters Brook (Exhs. HO-RR-53; HO-RR-94A; HO-RR-94B). The MA WMA permitted withdrawal rates, originally set in the 1989-1990 permits, were reaffirmed in 1995-1997 in conjunction with Town requests for new wells (Exhs. HO-RR-94A; HO-RR-94B).[99] The Company stated that a 1989 MA DEM report on the Blackstone River basin and its subbasins identified Peters Brook as a cold water fishery and possible habitat for the American Brook Lamprey, but did not conclude that special constraints should be placed on Town of Bellingham withdrawals from Peters Brook (Exhs. HO-RR-53; HO-RR-94A; HO-RR-94B). The Company added that the Town of Bellingham's water withdrawal permit for the Blackstone River basin wells had been reissued since publication of MA DEM's report, and reaffirmed previously-authorized withdrawal amounts without placing any special restrictions on such withdrawals (Exhs. HO-RR-53; HO-RR-94A; HO-RR-94B).

The Company also provided a copy of a water conservation plan for Bellingham and Blackstone developed by the CRWA and funded by the Company (Exh. HO-RR-55.1). The Company stated that it initiated the CRWA water conservation program ("CRWA program") to reduce demand on the Town of Bellingham's water supply system (Tr. 9, at 110 to 111; Tr. 10, at 12 to 16). According to CRWA estimates provided by the Company, total savings of drinking water and groundwater resources in Bellingham and Blackstone from the CRWA program would be 138.9 mgy and 18.26 mgy respectively. The program would include five projects with estimated benefits for the two towns, combined, as follows: retrofitting of toilets and shower heads (6.5 mgy savings to drinking water), leak detection (105.4 mgy savings to drinking water), public awareness program (27 mgy savings to drinking water),

99 The Company's witness, Mr. Friend, indicated that MDEP's review of requests for new or increased well withdrawals generally includes review of results of a long-term pump test, five days or more, together with monitoring of possible effects on water levels in any nearby wetlands or surface water bodies (Tr. 16, at 45 to 46, 57 to 61). He also explained that the MA WMA permits authorizing the new Town of Bellingham withdrawals included requirements for implementation of leak detection and other water conservation measures, and added that such requirements are standard in MA WMA permits (id. at 49 to 55).

stormwater remediation program for recharge infiltration (12 mgy recharge to groundwater), and septic system repair (6.26 mgy recharge to groundwater) (Exhs. HO-RR-55.1; HO-RR-86; HO-RR-87).

The Company admitted that its planned use of steam augmentation to increase the output of the proposed project during periods of peak load would substantially increase its water consumption (Tr. 11, at 112, 116 to 117).[100] The Company noted that conventional peaking facilities, which serve the same role as steam augmentation, can, depending on technology, operate with no more water than that necessary for sanitary needs (id. at 115 to 116). However, the Company argued that the impacts of conventional peaking facilities, including land use, noise, visual, safety and, potentially, air impacts, would more than offset the water use impacts of the proposed facility (id. at 108 to 109).

With respect to relative costs, the Company asserted that a conventional peaking unit would involve higher heat rate (lower efficiency) and greater cost than would comparable output from steam augmentation at the proposed facility (Exh. HO-RR-72; Tr. 11, at 122 to 123).[101,102] The Company stated that the increase in design and capital costs of construction

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100 The Company also assessed the frequency and extent of steam plumes from the facility stack based on proposed facility operation, including use of steam augmentation, and analyzed related visual impacts (see Section III.B.c, below).

101 The Company explained that the heat rate for the proposed GT-24 unit would be 24 percent higher (less efficient) during steam augmented operation than it would during baseload operation (Exh. HO-RR-72). By comparison, the Company stated that the heat rate for a new simple cycle peaking unit would be 44 to 64 percent higher than that of the proposed facility during baseload operation (id.).

102 The Company also investigated means by which to achieve greater capacity output from the proposed facilities either on a peaking basis or as increased baseload capacity (Exh. HO-RR-65, at 3-36). The Company indicated that all such options involved significant redesign of the proposed facilities and/or a reduction in baseload efficiency, with resulting increases in cost which would make the plant less competitive in a deregulated market (id.). With respect to increasing baseload capacity, the Company stated that a plant running at a higher yearly baseload capacity average cannot accrue the same economic benefits as a plant designed to increase plant output significantly for shorter periods of time (id.). The Company contended that additional peaking power would be more useful in New England where certain quantities of peaking power are needed at short notice (id.).

associated with steam augmentation capability would be negligible, and that no incremental fixed costs would be associated with steam augmentation (Exh. HO-EW-8). The Company stated that the additional variable operating costs would include the cost of water, water treatment and supplemental fuel costs (id.). The Company stated that steam augmentation would result in additional water resource impacts but asserted that such impacts would be offset by the CRWA program (id.).

The Company stated that no portion of the facility footprint or its related features on the site, including the temporary parking and laydown areas during construction, would be located within jurisdictional wetlands (Exh. HO-RR-70; Tr. 10, at 86 to 87). The Company indicated however, that some components ancillary to the proposed facility, such as the access roadway and some of the stormwater drainage features, would be placed within the 100-foot buffer zone of bordering vegetated wetlands (Exh. HO-RR-70; Tr. 10, at 87).

The Company asserted that impacts to wetlands associated with installation of the off-site portion of the natural gas pipeline interconnect for the proposed facility could be minimized by the use of directional drilling to cross the Charles River (Tr. 10, at 90 to 92). The Company stated that AGT, which would be responsible for the installation of the natural gas interconnect for the proposed facility, estimated that directional drilling would disturb approximately 131 square feet of nonforested wetland area at the Charles River (id. at 92). Algonquin expected that impacts to wetlands along the remainder of the route would total 32,000 square feet (id.).

The Company indicated that the use of air cooled condensers and internal water recycling would result in low wastewater flows (Exh. BEL-15, at 12-5). The Company stated that process discharge volumes would range from approximately 3,400 gpd during normal baseload operations to 5,000 - 8,000 gpd when the proposed facility operates with frequent stops and starts (id.; Exh. NEA-13). The Company stated that the use of steam augmentation would not affect wastewater discharge volumes (Tr. 11, at 138). The Company further stated that a greater discharge volume, 17,300 gpd on average and 27,000 gpd at maximum, would occasionally result due to equipment blowdown, equipment washdown, and maintenance activities (Tr. 11, at 135 to 136).

The Company documented allocation by the Town of a firm 10,000 gpd of average daily sewer capacity at the Charles River Pollution Control District Plant for the proposed facility (Exh. HO-RR-BCC-1). The Company stated that discharge from major maintenance inspections would occur over periods of up to several days, but that the Town would make special provision to allow the proposed facility to discharge its maximum anticipated wastewater discharge as necessary (Exh. HO-RR-63; Tr. 11, at 134 to 137). The Company indicated that oil contaminated effluents would be routed through an oil separator before being discharged to the sewer system (Exh. BEL-1, at 6-30).

The Company indicated that it had developed a stormwater management plan for the proposed facility designed to minimize pollutants in the proposed facility's stormwater discharges, assure compliance with the terms and conditions of the National Pollutant Discharge Elimination System ("NPDES") Multi-Sector General Permit requirements, attenuate peak stormwater runoff discharge rates to values not greater than the predevelopment rates, and meet the Massachusetts Stormwater Management Performance Standards (Exh. BCC(2)-W5.1, at 4-1; Tr. 11, at 155). The Company provided a copy of its Notice of Intent to the Bellingham Conservation Commission containing details of its stormwater management plan (Exh. BCC(2)-W5.1). The Company stated that peak stormwater runoff rates with the facility in operation actually would be less than the peak runoff rates under existing site conditions as a result of its proposed stormwater management plan design (id. at 4-8). The Company further stated that it anticipated no deterioration of off-site resources due to the water quality of stormwater runoff from the proposed facilities (id. at 4-8).

(2) Positions of the Intervenors

The Town of Franklin argued that the Agreement executed by the Company and the Town of Bellingham would not limit the Company's water withdrawals from Bellingham's water supply to 100,000 gpd during March 15 through November 15 and 250,000 gpd during the period November 15 through March 15, as stated by the Company (Franklin Brief at 18 to 19; BCC Brief at 3 to 4). The Town of Franklin contended that the Company would not necessarily be limited to withdrawal of the water quantities specified in the Agreement, but only to withdrawal of specific quantities of water at the Town's standard rates (Franklin Brief at 19). The Town of Franklin further argued that the Agreement explicitly acknowledged the Company's ability to withdraw additional quantities of water because it allowed for billing the Company at a rate 1.4 times the highest rate block for all usage over the specified amounts indicated (id.). In addition, the Town of Franklin took issue with the statement by the Company's witness that the Town of Bellingham would control any deliveries of Town water to the Company beyond the 100,000/250,000 gpd levels described (id.). The Town of Franklin argued that Bellingham has no legal authority to refuse to supply water to the Company when such water is available, and that the Agreement does not purport to confer such authority (id. at 19 to 20). On the basis of its arguments, the Town of Franklin urged the Siting Board, in the event the proposed facility was not denied, to prohibit or limit steam augmentation at the proposed facility and to limit the Company's daily and average daily water usage (id. at 29).

The Bellingham Conservation Commission submitted arguments mirroring those of the Town of Franklin with respect to water supply for the Company's proposed facility in Bellingham (BCC Brief at 3 to 4). On the basis of arguments presented, the Bellingham Conservation Commission asserted that approval of the Company's proposed facility should only occur given some guarantee that withdrawals for the proposed facility would not exceed 100,000 gpd from March 15 to November 15, and 250,000 gpd from November 15 to March 15 (id.).

The Town of Franklin and the Bellingham Conservation Commission also expressed concern regarding the wetlands impacts of Algonquin's proposal to construct a natural gas pipeline under the Charles River to the proposed site (Franklin Brief at 28 to 29; BCC Brief at 4-5). The Town of Franklin argued that the Algonquin interconnect and the proposed facility are part of the same project and that the temporary and permanent impacts to bordering vegetated wetland are in excess of DEP's standards (Franklin Brief at 28 to 29). The Town of Franklin further asserted that there is a "reasonable alternative route" for the proposed pipeline -- the entire project could be located at another site in Bellingham, avoiding a Charles River crossing -- and that the proposed facility therefore fails to comply with DEP wetland standards (id.).

The Bellingham Conservation Commission noted that Algonquin has not committed to using directional drilling to cross the Charles River, and that the alternative, an open trench crossing, would have significantly greater impacts to wetlands (BCC Brief at 4 to 5). In addition, the Bellingham Conservation Commission indicated that it had identified route modifications that could eliminate alterations to wetland number one as identified in Algonquin's 401 Water Quality Certification Application for the proposed natural gas pipeline interconnect (id. at 5). The Bellingham Conservation Commission argued that use of directional drilling and adoption of its suggested route modifications were key to minimizing the wetlands impacts associated with the proposed natural gas pipeline interconnect (id.). The Bellingham Conservation Commission also wished to ensure that an appropriate review would occur if the Company decided to pursue a second gas utility interconnection to Tennessee Gas Pipeline (id.).

The Town of Franklin expressed concern with respect to the amount of wastewater discharge capacity available to the Company at the Charles River Pollution Control District and argued that the Company should develop a contingency plan for trucked removal of wastewater beyond its daily average capacity discharge (Franklin Brief at 22).

(3) Analysis

ANP has undertaken a significant and effective design effort to minimize the proposed facility's water supply needs during baseload operation. The record demonstrates that, due to the incorporation of air cooled condensers and other water conservation measures, the water supply needs of the proposed facility during baseload operation can be met with 14,000 gpd -- substantially less (by a factor of more than two) than the water supply needs of the most water-efficient plant previously approved by the Siting Board (see n.93, below). The Siting Board therefore finds that the water supply impacts of the proposed facility have been minimized during baseload operations.

ANP also proposes, however, to bolster the output of the proposed facility with steam augmentation for up to 20 percent of the operating year. Assuming use of steam augmentation for 10 percent of the operating year -- the level that the Company expects -- water use would increase to an average of 96,600 gpd. The Company argues that the proposed use of steam augmentation is consistent with the Siting Board's mandate to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

According to the Company's calculations, steam augmentation at the proposed facility would use 28,500 gallons of water per hour to increase power production by 40 MW at times of peak demand. The Siting Board notes that, even assuming operation with steam augmentation for 20 percent of the operating year, the proposed facility would use less water on a per-MW basis than any generating facility previously approved by the Siting Board.[103]

The Company has argued that producing comparable additional power with a conventional peaking unit or other alternative would (a) cost more to construct and operate and (b) involve a range of undesirable environmental consequences which would more than offset the extra water use of the proposed project. The record indicates that, in contrast to identified alternatives, ANP's proposed peaking capability would involve essentially no additional capital cost. Further, proposed operation with steam augmentation would achieve a better heat rate than new simple cycle peaking capacity and, unlike other alternatives, have no adverse effect on baseload operating efficiency. The proposed peaking capability also would result in lower regional air emissions than alternatives,[104] given its efficiency advantages, and would avoid land use and other environmental impacts associated with alternative new construction of peaking capacity.

Given these benefits, and the proposed facility's low per-MW water consumption even during steam augmentation, the Siting Board agrees that steam augmentation would contribute

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103 Based on use of 54.2 mgy with steam augmentation 20 percent of the year, the proposed project would use approximately 99,450 gpy per MW of baseload capacity. The comparable usage rates in recent reviews were: 224,000 gpy per MW for the 170 MW air-cooled Dighton Power project; 2.4 mgy per MW for U.S. Generating Company's 360 MW water-cooled project in Charlton; and 2.0 mgy per MW for the 252 MW water-cooled Berkshire Power project in Agawam. Dighton Power Decision, EFSB 96-3, at 219, 240; Millennium Power Decision, EFSB 96-4 at 58, 118-119; Berkshire Power Decision, 4 DOMSB at 313-314.

104 To the extent that, based on economic dispatch, the proposed project displaces existing rather than new peaking capacity, air emission benefits likely would be greater.

to a least-cost, least-environmental impact energy supply if associated water impacts are acceptable given resource constraints. The question of the acceptability of water impacts hinges in particular on whether the proposed facility's water use will strain the Town of Bellingham's municipal water supply or the basin resources on which the water system relies. We therefore examine the water consumption of the proposed facility in terms of water availability, impact on watersheds and proposed mitigation. Because of the number of proposed and existing power plants in the Bellingham-Blackstone area, we consider issues related to the water consumption of the proposed Bellingham facility in the context of existing water use at the Milford Power and NEA facilities, and the proposed use by the Bellingham, Blackstone and IDC facilities.

The Company claims that it has signed a contract which will limit water withdrawals for its proposed facility to levels well within the capacity of Bellingham's municipal water system and its contributing watersheds. The record demonstrates that ANP will have the right to withdraw water in quantities of up to 100,000 gpd during the period March 15 through November 15, to be billed according to the rate structure used for billing all customers of the Town of Bellingham's water system, and in quantities of up to 250,000 gpd during the period November 15 through March 15, to be similarly billed. The record also shows that there is provision in the Company's Agreement with the Town for the Company to be billed at a rate of 1.4 times the highest rate block for all usage over the daily averages noted above. It cannot be definitively determined, based on the Company's Agreement with the Town of Bellingham, that the Company is contractually limited to 54.75 mgy from the Bellingham municipal water system. It is significant, however, that the Company has stated on the record that this is its impression of its Agreement with Bellingham.[105] The Siting Board also recognizes that steam augmentation provides peaking capacity, and that the Company's expectation that it will use steam augmentation approximately 10 percent of the time therefore is realistic. The Siting Board notes that even under the Company's highest

[105] <u>See</u> Tr. 11, at 126 to 127.

water use scenario, which involves the use of steam augmentation for 20 percent of the year, maximum water withdrawal from Bellingham's water supply would be 54.2 mgy.[106]

The record also demonstrates that the permitted capacity of Town wells can accommodate withdrawals for the proposed facility at the rate of 54.2 mgy in addition to all other present Town withdrawals. In addition, the record demonstrates that the combined water supply requirements of the Town and the proposed facility will continue to increase more slowly than the permitted capacity of Town wells under the MA WMA. Furthermore, while new development over time can be expected to result in additional water customers, the record demonstrates that water use increases in Bellingham have slowed in recent years and are projected to increase at a declining rate over time (see Exh. HO-RR-52, at 2).

With respect to the Company's analysis of the impact of projected withdrawals from the Bellingham municipal water supply, the record demonstrates that, based on 1993-1996 data, precipitation recharge for Town of Bellingham wells is above the combined levels of average annual aquifer withdrawals plus future annual withdrawals for the proposed facility. In addition, the record demonstrates that there are no conflicts between the proposed facility's demand on the public well system in Bellingham and the use of private wells, because the aquifers drawn upon are likely to be different.

Water for the proposed facility will be withdrawn from Town of Bellingham wells in two watersheds, those of the Charles and the Blackstone Rivers. Water from the Blackstone River will come, more specifically, from Peters Brook, a Blackstone River tributary.
The record demonstrates that the Blackstone River basin as a whole has ample resources for Bellingham town wells even with withdrawals for the proposed facility, but that the water resources of the Charles River basin and the Peters Brook subbasin are more thinly stretched. In these two waterways, water requirements for the proposed project and permitted increases in water withdrawal of the Town represent a larger share of 7Q10 flow. While withdrawals from the Charles River and Peters Brook are not presently restricted, the record shows that state withdrawal permits do not require extensive environmental review. In addition, the Bellingham-Medway aquifer contributes to the streamflow of the Charles River as well as

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106 See Tr. 10, at 135 to 136.

underlying four of the Town of Bellingham wells which would supply water to the proposed facility. The record contains reports which document the efforts of water managers to assess long-term water availability, consistent with maintaining environmental objectives such as ensuring minimum streamflow or otherwise protecting identified resources. Thus, meeting commonly cited minimum streamflow criteria, if required for the Charles, might trigger corresponding limits on withdrawals from the Bellingham-Medway aquifer. Given such potential conflicts and constraints, the Siting Board cannot simply rely on the Company's argument that its water withdrawals would be a small percent of downstream flow in order to conclude that its proposed water use with augmentation is consistent with minimizing environmental impact.

These real concerns about watershed impacts are offset by the fact that the Company intends to fund a CRWA-developed water conservation program for Bellingham and Blackstone, which is expected to reduce water demand and improve water use efficiency, providing net benefits of 1.4 times the combined withdrawals of the ANP Bellingham and ANP Blackstone facilities, assuming steam augmentation 20 percent of the year. The Siting Board notes that this estimate is subject to some uncertainty. For example, water savings from leak detection efforts may be overstated due to existing leak detection programs, and undetected leaks may flow to the same aquifers from which municipal water supplies are drawn. Nonetheless, the Company-funded program is likely to produce significant water conservation benefits in the vicinity of the proposed facility, and has the potential to fully or substantially offset the water requirements of the proposed facility -- a level of mitigation not present in previous Siting Board reviews in which water use was an issue.[107]

The Siting Board commends ANP's creative approach to mitigating the water supply and associated water resource impacts of its proposed facility. We view the CRWA program

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107 The Siting Board notes that, although implementation of leak detection and other water conservation is required as part of MA WMA permits for Town of Bellingham withdrawals, the commitments in the CRWA program relating to funding by ANP and oversight by CRWA go well beyond requirements in MA WMA permits, and provide significantly greater assurances that conservation measures actually will be implemented.

as a model for would-be developers of future generation projects to emulate, particularly at sites where water supply is or may likely become a special concern. The level of mitigation offered by the Company-funded CRWA program is particularly important given that the proposed facility would be sited in an area where impacts on water supply include several existing and planned generation projects in addition to the proposed facility. In this setting, it is both important and appropriate that a new consumptive water use of the size the Company proposes be mitigated by a program capable of substantially, if not fully, offsetting the added water use. It is similarly important, on a community level, that the progress to date in holding down or avoiding water use increases be maintained.

Given their importance, it is appropriate that the commitments and expectations in the record relating to community water use and conservation be monitored. Toward that end, the Siting Board directs the Company to work with CRWA to ensure periodic documentation of program activities and results to the Company, and to share periodic reports with Town of Bellingham officials and the Siting Board.

The Bellingham Conservation Commission and the Town of Franklin have both expressed concerns with respect to the Company's proposed water usage. The Town of Franklin has asked the Siting Board, in the event the proposed facility is not denied, to limit the Company's water usage on a daily or average daily basis. However, as is clear from the analysis above, it is annual, and not daily, impacts to groundwater which are of concern.[108] Based on the Siting Board's analysis, even the Company's projected maximum water withdrawals will fall within the Company's contractual limits for water at standard rates from the Town of Bellingham's municipal water supply system. The record also shows that the financial disincentives are such that the Company is unlikely to withdraw more water than the projected maximum for its proposed facility. In addition, impacts on watersheds are acceptable, given recent trends in community water use and the extent of mitigation offered by the proposed CRWA program. Thus the Siting Board is satisfied that the Company has

108 The Siting Board also notes that the wells of the Towns of Franklin and Bellingham pump water from different aquifers. Bellingham's town wells in the Charles River watershed are located on different branches or tributaries of the Charles than are Franklin's.

addressed concerns associated with water withdrawals for its proposed facilities; specifically, the Siting Board sees no need to impose the condition requested by the Town of Franklin.

Accordingly, the Siting Board finds that with implementation of the above condition, the environmental impacts of the proposed facility would be minimized with respect to water supply.

The record demonstrates that impacts to wetlands and wetland buffer zones on-site would be minimized. However, some question remains as to whether the wetlands impacts associated with construction of the natural gas pipeline interconnect for the proposed facility will be minimized. The use of an open trench crossing, rather than directional drilling, to cross the Charles River would greatly increase the total wetlands impacts resulting from construction of the proposed facility and associated projects, and it remains unclear at this time whether Algonquin is committed to using directional drilling techniques.

While the natural gas pipeline interconnect is ancillary to the proposed facility, it is subject to the jurisdiction of the FERC, rather than the Siting Board, and its route is therefore not the subject of this proceeding. However, concerns about its impacts will not go unaddressed. The Siting Board regularly intervenes with respect to the environmental impacts of such pipeline projects before the FERC. In addition, Algonquin's plans for installing its proposed gas pipeline across the Charles and through bordering vegetated wetlands are addressed by the Bellingham Conservation Commission in its review of Algonquin's Notice of

Intent for its proposed project.[106] (See Section III.B.2.g, below, for a discussion of land use impacts related to the AGT pipeline.)

The Siting Board notes that a second gas utility interconnection to Tennessee Gas Pipeline at this time would constitute a change in plans for the proposed facility, requiring Siting Board notification. If the Company opts to install a second gas utility interconnection in the future, such construction also would require filings with FERC and the Bellingham Conservation Commission.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to on-site wetlands and construction impacts.

The Company has demonstrated that it has a comprehensive plan for minimizing impacts to all water resources resulting from wastewater and stormwater discharge from the proposed facility, and that its plan meets all applicable government regulatory policy requirements.

Accordingly, the Siting Board finds that impacts to all water resources resulting from wastewater and stormwater discharge from the proposed facility would be minimized.

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106 The Bellingham Conservation Commission already has expressed its concern that AGT's proposal for crossing the Charles River and associated wetlands maintains the option to use an "open trench" crossing in the event that a directional drill can not be completed (BCC Brief at 5). In response, the Company asserted that directional drilling is expected to be used, and that review by FERC would ensure that the environmental impacts of the gas pipeline interconnect would be minimized consistent with FERC standards (Company Brief at 137).

AGT's proposed pipeline and route are detailed in FERC Docket No. CP98-100-000, as are the Siting Board's comments. In our filed comments, we recommend avoidance or minimization of wetlands impacts, including the use of directional drilling between the Charles River, and post construction restoration of impacted areas (Environmental Comments of the EFSB in Docket CP98-100-000, March 20, 1998).

c. Visual Impacts

(1) Description

The Company submitted an evaluation of the potential visual impacts of the proposed facility at the proposed site (Exh. BEL-1, at 6-70 to 6-82; HO-EA-4.1, at 5-22, and App. C; HO-EV-1 to HO-EV-15; HO-RR-38 to HO-RR-45; TF-AP1, TF-AP-2, TF-AQ-10; F-RR-3 to F-RR-6). As part of its evaluation of visual impacts, the Company conducted viewshed analyses of the surrounding areas (Exh. BEL-1, at Figs. 6.7-1 to 6.7-10). The Company identified and mapped areas within approximately 1.5 to 2.0 miles of the proposed site from which the 180 foot stacks and other facility structures might be visible (id. at 6-72). Within areas identified as potentially having views of the proposed facility, the Company selected a number of visual receptor points on the basis of land use, proximity to the site and potential impacts (id. at Figs 6.7-1 to 6.7-10). The Company provided additional visual receptor locations and modified certain of the exhibits at the request of Staff and an intervenor (Exhs. HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6). The Company presented existing views for a range of seasonal conditions by means of photographs taken at the identified locations looking toward the proposed site (Exhs. BEL-1, at Figs. 6.7-1 to 6.7-10; HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6). For each photograph, the Company then developed a computer-generated perspective of the proposed facility as it would appear at that specific location, and superimposed the perspective on the associated photograph (Exhs. BEL-1, at Figs. 6.7-1 to 6.7-10; HO-EV-6.1-6.6; HO-RR-38 to HO-RR-45; F-RR-3 to F-RR-6).

The Company also analyzed the meteorological and operating conditions under which visible exhaust plumes likely would emanate from the main stacks of the proposed facility (Exhs. HO-EA-4.1, at 5-22; HO-EV-10 (Rev.)). The Company indicated that over the course of a year, plumes of over 50 meters would be visible approximately 50 percent of daylight hours, and plumes of 100 meters or more would be visible approximately 28 percent of the daylight hours (Exh. HO-EV-10.1 (Rev.)).[107] The Company also described the MDEP

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107 In its analysis, the Company assumed 5110 daylight hours per year, and that the (continued...)

standard with respect to the opacity[108] of plumes from fossil fuel utilization facilities, and indicated that plume opacities for the proposed facility would be well below the regulatory limit of 20 percent (Exh. HO-EA-4.1, at 3-6, App. C.; Tr. 7, at 45-46).

Finally, the Company indicated that it had reviewed the Massachusetts Landscape Inventory, and had determined that no distinctive or noteworthy landscapes are identified in the project vicinity, and that therefore no such areas would be impacted by the proposed facility (Exh. HO-EV-9).

The Company asserted the proposed facility would be screened from view in most directions and that, at those locations where the facility would be visible, its effect would generally be limited by surrounding land uses, terrain, vegetation and distance (Exh. BEL-1, at 6-70 to 6-74). In addition the Company asserted, citing an approved Special Permit from the Bellingham ZBA, that views of the proposed facility would be consistent with the industrial zoning of the proposed site and its immediate surroundings (Company Brief at 147).

The Company indicated that both the facility structures and stacks would be visible from certain areas to the east of the facility, including portions of Maple Street and adjacent properties, including residences, a restaurant, and a golf course (Exhs. BEL-1, at 6-80, 6-81; HO-RR-44; Tr. 8, at 61, 70, 74). The Company indicated that after construction, it would replant trees along the western edge of the NEP ROW (except in the area of the electrical interconnect) in order to screen views of the facility from locations along Maple Street (Tr. 8, at 98-100). The Company added that views of the facility from receptors to the north, west and south of the site generally would be limited to more distant views of the stack tops as

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[107](...continued)
proposed facility would operate with steam augmentation for 38 days per year (Exh. HO-EV-10.1 (Rev.)). The Company stated that the model excluded 1179 hours per year during which it assumed that ambient meteorological conditions (i.e., periods of rain, fog or overcast sky) likely would reduce or obscure plume visibility (id.; Tr. 15, at 14-23). The Company noted that the excluded hours would be expected to include periods of increased plume length due to the higher levels of atmospheric moisture that are often present under such conditions (id. at 17-18).

[108] The Company defined "opacity" qualitatively in terms of thickness, or the capability of a plume to obstruct the passage of light (Tr. 7, at 45-46).

seen through and above existing vegetation (Exh. BEL-1, at 6-74 to 6-82). The Company provided additional viewshed exhibits from residential areas further to the northeast, east, and south within the Town of Franklin and indicated that views of the facility from these locations, where present, also would be limited by distance and would be restricted to the tops of the stacks as seen above existing vegetation (Exhs. HO-EV-6; HO-EV-13; F-RR-4; F-RR-5; Tr. 8, at 46).

The Town of Franklin argued that the Company had failed to characterize adequately the visual impacts of the proposed facility because its viewshed exhibits did not include representations of visible plumes from the facility stacks, despite evidence in the record which indicated that visible plumes of 50 meters or more in length would be visible for greater than 50 percent of daylight hours (Tr. 8, at 131-133; Tr 15, at 24; Franklin Brief at 17; Franklin Reply Brief at 6). Citing testimony by Mr. Sellars that operating with steam augmentation results in longer, more visible plumes, Franklin further asserted that the Company could mitigate the visual impact of plumes by foregoing steam augmentation (Franklin Reply Brief at 6). The Company responded that because presence and length of visible plumes is intermittent and variable, there would be little value in attempting to provide visual representation of plume impacts (Company Reply Brief at 16).

The Company stated that the facility structures will be painted a neutral color, typical of modern industrial buildings, to minimize the visual impacts of the proposed facility (Exhs. BEL-1, at 6-71; HO-EV-7; Tr. 8, at 57-60, 78-85). The Company explained that in selecting the final color(s) for the proposed facility, it intended to consider opinions expressed by both citizens and local officials, and would also rely to a degree on the experience of its EPC contractor, ABB, regarding color choice (Tr. 8, at 59-60).

With respect to exterior lighting, the Company stated that the primary purpose of exterior lighting is to provide safe working conditions on and around the facility structures (id. at 27). The Company indicated that permanent exterior lighting likely would be located up to about the 100-foot level on the facility, or the approximate elevation where the HRSGs meet the 180-foot high stacks (id. at 9). The Company also stated that the FAA had determined that aviation lighting in the form of steady red beacons would be required at the top of the stacks (id. at 8). The Company stated that the final lighting design would attempt to minimize the visual impact of exterior lighting by using fixtures that would be oriented downward, and by using dark surfaces, where possible, to reduce reflectivity (id. at 27, 31; Exh. TF-AP-1).

As further mitigation for visual impacts, the Company stated that it would make certain off-site mitigation measures available to property owners in the vicinity of the proposed site (Exhs. HO-EV-7; HO-EV-14; Tr. 8, at 90-98, 100-107).[109] The Company stated that such mitigation typically would involve plantings of shrubs or trees to screen views of the facility, but could also include installation of window awnings or other reasonable and mutually agreeable measures (Tr. 8, at 104). The Company indicated that it would consider requests for off-site mitigation of visual impacts for locations up to one mile from the proposed site, and would review all such requests on a case-by-case basis (Tr. 8, at 103).

(2) Analysis

The record demonstrates that the proposed facility would be screened from view in most directions, but would have the potential for pronounced visual impacts along sections of Maple Street and at nearby residential and commercial properties located primarily to the east of the proposed site.[110] However, the Company's analysis indicates that views of the facility likely would be limited to the upper portions of the stacks as seen above existing trees at the majority of viewshed locations.

In addition, the record indicates that visible plumes of 50 meters or more in length would occur during approximately 50 percent of daylight hours. These plumes likely would

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109 The Company stated that it would provide information to the public regarding the availability of Company-sponsored off-site mitigation of visual impacts by means of a liaison contact within the local community that would be established to receive and address the concerns of residents with respect to visual and other potential impacts of the facility (Tr. 8, at 104-107).

110 The Siting Board notes that the proposed replanting of the western edge of the NEP ROW following construction likely would soften views of the facility from many of these areas.

be visible from areas where views of the facility structures themselves would be significantly limited or would not be visible.

With respect to the position of Franklin concerning the proposed use of steam augmentation and its associated visual impacts, the Siting Board is not persuaded that the increased visual impacts associated with steam augmentation would merit the dismissal of such technology as a design option for the proposed facility. The Company's plume visibility analysis assumed the base case scenario of just over 38 days per year of steam augmentation. Therefore, while steam augmentation is a contributing factor to plume visibility, it likely is not the determining factor for a majority of the 2571 hours (107 days) per year that visible plumes with lengths of 50 meters or more are expected. In addition, to the extent that steam augmentation would result in some additional hours of visible plumes, the Siting Board has recognized that the ability of the proposed facility to provide added capacity during peak load periods represents an important environmental advantage as it could reduce the need for new peaking units elsewhere, and therefore would avoid their associated site-specific impacts including the construction-related, land use and visual impacts of installing such units. For a comprehensive discussion of the proposed steam augmentation technology and related environmental impacts, see Section III.B.2.b, above.

With regard to the general appearance of the facility and related structures, the Company has indicated that in addressing issues such as building color, the effect of nighttime lighting at the site, and other related aesthetic concerns, it intends to seek consensus among its EPC contractor, local officials and other concerned parties in order to resolve such issues in a mutually satisfactory manner. The Siting Board agrees that it is appropriate for the Company to consider input from such groups on these issues to the extent possible, and encourages the Company to involve the various stakeholder groups in discussions of those final project design features, such as color, that would promote the integration of the proposed facility with its surroundings.

In three recent reviews, the Siting Board has required proponents of generating facilities to provide selective tree plantings in residential areas up to one mile from the proposed stack location to mitigate the visibility of the facility and the associated stack. Millennium Power Decision, EFSB 96-4 at 140; Dighton Power Decision, EFSB 96-3 at 47-48; Berkshire Power Decision, 4 DOMSB at 395.[111] Here, the Company has expressed a willingness to consider mitigation of visual impacts at locations within one mile of the proposed site where views of the facility are considered to be significant. The proposed mitigation would include provision of shrubs, trees, window awnings, or other reasonable forms of mitigation, if requested by local residents. Consistent with Siting Board precedent concerning the minimization of visual impacts, the Siting Board directs the Company to provide reasonable off-site mitigation of visual impacts, including shrubs, trees, window awnings or other mutually-agreeable measures, that would screen views of the proposed facility at properties along Maple Street, and at other locations within one mile of the proposed facility, as requested by residents or appropriate municipal officials.

In implementing its overall plan for off-site mitigation of visual impacts, the Company: (1) shall provide shrub and tree plantings, window awnings or other reasonable mitigation on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to appropriate officials in Bellingham and Franklin, and to all potentially affected property owners in those communities, prior to the commencement of construction; (3) may limit requests for mitigation measures from local property owners and municipal officials to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all agreed-upon mitigation measures within one year after completion of construction, or if based on a request filed after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance and replacement of plantings, as necessary, to ensure that healthy plantings become established.

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

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111 Based on evidence in the record, examples of these areas would include the locations depicted in the following exhibits: Exhs. BEL-15, Figs. 6-3, 6-4 and 6-10; HO-EV-6.2, HO-EV-6.3 and HO-EV-6.4.

d. Noise

(1) Description

The Company asserted that the projected noise impacts of the proposed facility at the proposed site would not adversely affect neighboring residences or properties and would be minimized in accordance with Siting Board standards of balancing environmental impacts consistent with minimizing costs (Exhs. BEL-1, at 6-74; BEL-15, at 8-1). The Company also asserted that noise impacts from the operation of the proposed facility would: (1) comply with the MDEP ten-decibel limit on noise increases at all residential receptors, as detailed in Policy 90-001 ("MDEP Standard"); and (2) cause no adverse impacts at the facility property lines based on the extent of buffer, the presence in some locations of non-residential land uses and zoning, and applicable federal guidelines for non-residential exposure (Exhs. BEL-1, at 6-74; HO-EA-4.1, App. D at 13, 38; HO-EN-1.1; HO-EN-22; Tr. 13, at 83-85). The Company further stated that the worst-case noise impacts during on-site construction activity would be intermittent and temporary in nature, and that noise from construction traffic would be noticeable at nearby residences, but that such impacts would not be significantly greater than noise from existing traffic flow in the area[112] (Exh. BEL-1, at 6-88 to 6-94).

The Company stated that an increase of 3 decibels is the minimum increase in sound level that is generally perceptible to the human ear (Tr. 13, at 39-41). The Company stated that there are various measures of noise, and indicated that the MDEP Standard which limits allowable noise increases to 10 dBA is based on a relatively quiet measure of noise that essentially is the background sound level that is observed in the absence of louder, transient sounds (Exh. BEL-15, Vol. 1, at 8-3). The Company stated that for purposes of noise analysis in this case, the background level is defined as that level of noise that is exceeded 90 percent of the time ("L_{90}") (id. and at 8-4).

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112 The Company did, however, specifically assess the traffic noise impacts of the proposed 12:00 a.m. departure of a second construction shift (180 vehicle trips) from the facility site. The Company stated that during the half-hour period when vehicles likely would be exiting the site, noise impacts at area residences would be increased by up to 9 dBA (Exh. HO-RR-74).

To define the noise impacts from operation of the proposed facility, the Company provided analyses of existing noise levels and expected noise increases resulting from construction and operation of the proposed facility (Exhs. BEL-1, at 6-88; HO-RR-77.1, at 40). To establish existing background noise levels, the Company conducted surveys at four distinct locations having various distances and directions from the proposed site (Exh. BEL-1, at 6-88). The Company stated that it selected the four noise monitoring locations ("NMLs") in order to obtain an adequate spatial representation of the ambient noise environment as a basis for modelling project-related noise increases at the nearest affected residences and property lines (id. at 6-86). The Company stated that the four NMLs were located as follows: (1) along Route 126 near the intersection of the existing electric transmission line corridor (NML-1), and representative of residences located approximately 2000 feet northwest of the proposed site; (2) on Maple Street near Pine Street (NML-2), representative of residential locations to the northeast of the site; (3) further south along Maple Street (NML-3), proximate to residences east of the site; and (4) on the proposed site itself, within the project footprint area (NML-4) (id.).

For each NML, the Company provided a set of noise measurements taken during 20-minute sampling periods which the Company indicated were representative of daytime and nighttime periods for both weekday and weekend conditions (Exh. BEL-15, Vol. 2, App. C.). The Company noted that for each NML, the quietest ambient levels were observed during the nighttime monitoring periods (Exh. BEL-1, at 6-88).

With respect to construction noise, the Company provided estimates of maximum levels of construction noise on site, and equivalent levels of such noise at the nearest residences, which the Company stated were located along Maple Street approximately 1400 feet east of the proposed facility footprint (Exh. HO-RR-77.1, at 14). The Company asserted that construction noise impacts are often transitory, and that the operation of diesel-powered heavy equipment is typically the major source of such noise (Exh. BEL-1, at 6-93; Tr. 13, at 11-12). The Company estimated that maximum levels of construction noise at residences would be 60 dBA and that such levels likely would occur during the excavation and finishing phases of construction (Exh. HO-RR-77.1, at 16).[113] The Company asserted that during the ground clearing, foundations, and steel erection phases, maximum construction noise levels would range from 49 dBA to 56 dBA at the nearest residences (id.).

The Company also stated that cleaning and testing of the facility's pressurized systems would require steam blowouts during the final stages of construction and plant commissioning (Exh. TF-SB-1; Tr. 13, at 27-30). The Company indicated that it would use a patented "silent-blow" technique to attenuate noise from steam releases and that as a result, noise levels at the closest residences would be limited to 45 dBA during these events (id.; Exh. F-RR-17).[114]

The Company indicated that mitigation of construction noise would include: (1) complying with Federal regulations limiting truck noise, (2) limiting construction activities that are significant sources of noise to daytime hours, (3) ensuring that construction equipment manufacturers' normal sound muffling devices will be used and kept in good repair throughout the construction period, and (4) using silencing equipment to attenuate noise from steam-release events (Exhs. BEL-1, at 6-93; TF-SB-1; Tr. 13, at 19-22, 27-30).

To analyze the noise impacts of facility operation at residential and property line receptors, the Company provided estimates of facility noise, and combined facility noise and background noise, by receptor, for daytime and nighttime periods at five residential receptors and four property line receptors (Exh. HO-RR-77.1, at 40). Based on its analysis, the Company stated that during facility operation, daytime L_{90} increases would be zero to 5 dBA at residential receptors, and nighttime L_{90} increases would be 3 to 8 dBA, thereby satisfying the MDEP Standard at the residential receptors (id. at 41; Exh. HO-RR-78). The Company

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113 The Company qualified these levels as applying to construction noise generated at or near the project footprint area (Exh. F-RR-15). The Company projected that maximum noise impacts of 76 to 80 dBA at residences would result from construction activities on the facility access road, portions of which would be significantly closer to existing residences (id.). The Company asserted that such levels would be produced by earth moving machines and would be of brief duration (id.).

114 The Company stated that it would inform area residents in advance about steam release events so that any noise increases relating to these events would be readily identifiable as such (Exh. TF-SB-1).

further stated that daytime L_{90} increases at the property lines of the proposed site would range from 8 to 16 dBA, with greater increases and exceedances at night[115] (Exhs. BEL-1, at 6-96 to 6-97; HO-EN-7; HO-EN-22; HO-RR-77.1, at 41).

With respect to noise impacts at the property lines of the proposed site, the Company stated that only daytime increases were considered where abutting lands were committed to commercial or industrial uses (Exh. HO-RR-77.1, at 40). The Company indicated that combined facility plus ambient noise would be 50 dBA at PL-3A, resulting in a daytime increase of 8 dBA at the east property line,[116] and would be 58 dBA at PL-2, resulting in a daytime increase of 16 dBA at the west property line (id.). The Company projected combined facility plus ambient noise levels of 52 dBA at PL-1, resulting in a daytime increase of 10 dBA at the northwest property line (id.). The Company stated that at location PL-4, the northeast property line, the proposed site abuts a 'Suburban' zoning district which allows residential uses and that nighttime increases therefore would be explicitly considered at that location (id. at 41). The Company stated that combined facility noise plus ambient at PL-4 would be 46 dBA, resulting in a nighttime increase of 10 dBA at this location (id. at 40-41; see also Tr. 15, at 80-91).[117]

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115 The record indicates that the Company's initial assessment of noise increases at the eastern property line (PL-3) projected a nighttime L_{90} increase of 16 dBA (Exh. HO-EN-7). The Company's pending purchase of lands to accommodate its proposed facility access road would result in an eastward shift in the closest property line east of the proposed facility (Exh. HO-RR-77.1, at 10 to 11). The Company identified the new east property line as location PL-3A, and stated that the abutting parcel contains a commercial establishment, Ma Glockner's restaurant (id.).

116 The Company's ambient noise measurements at two nearby locations, NML-2 and NML-4, both show a nighttime L_{90} level of 36 dBA (Exhs. HO-RR-77.1, at 40; BEL-1, at 6-88). The Siting Board notes that if the background noise level at PL-3A is assumed to be 36 dBA, the nighttime L_{90} increase with facility operation would be 13 dBA.

117 The Company stated that future residential development on this lot would be unlikely because the lot currently is non-conforming and already supports a residence closer to its frontage with Maple Street (Company Brief at 189). Nevertheless, the Company recognized that if a future residential use were developed closer to the rear lot line,

(continued...)

The Company concluded that, during the daytime, facility noise levels would produce exceedances of the 10-dBA limit along a portion of the west property line and that, therefore, the proposed facility would require a waiver of the MDEP Standard (Exh. HO-RR-78). Moreover, the Company stated that at night, facility noise would result in exceedances along the western and northern property lines and probably at the eastern property line[118] as well (Exh. HO-RR-77.1, at 41). The Company indicated that it would seek a property line waiver as part of the Air Plans review for the proposed facility, and maintained that it expected to receive such waiver from MDEP based on zoning and the presence of either wetlands or existing commercial uses that would preclude residential development on affected lands[119] (id.; Exhs. HO-RR-77.1, at 41; HO-65.1 at 3-20; Company Brief at 157). In support of its contention, the Company cited prior instances in which MDEP had relaxed its standard based on a determination that present and future residential development would not be possible (Exh. HO-RR-65.1, at 3-20).

With respect to noise impacts at residential locations, the Company indicated that nighttime L_{90} levels at the nearest residences would range from 40 dBA to 44 dBA

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[117](...continued)
the conditions of the Town of Bellingham ZBA Special Permit (see Exh. BEL-30.1) with respect to noise would apply, and would require the Company to limit the L_{90} noise increase to 8 dBA at any such residence (id. at 158).

118 The Town of Franklin therefore argued that the MDEP waiver would need to explicitly consider that portion of the eastern property line for which nighttime exceedances would be greater than 10 dBA (see n.115, above) (Exh. HO-RR-78; Franklin Brief at 26). The Siting Board concurs and notes that nighttime exceedances along the east property line would be of particular concern due to the presence of an existing light commercial use and the proximity of residential uses.

119 The Company also noted that noise levels at the property lines would be in compliance with Town of Bellingham Code of Zoning By-Laws (Article III, Sec. 3220) which allow sources located within business and industrial districts to result in continuous exterior noise levels of up to 65 dBA at the property line (Exhs. HO-RR-77.1 at 9; HO-EL-9.1 at 20). Under a Special Permit from the Bellingham ZBA, noise increases from the facility must not exceed 8 dBA at any residential receptor not owned by the Company (Exh. HO-RR-30.1, App. 1 at 5).

(Exh. HO-RR-77.1, at 40). Based on its noise analysis, the Company identified receptor R-4B, a house located at 169 Maple Street, as the most affected residential location[120] (id.). The Company stated that nighttime L_{90} noise at this location was measured at 36 dBA and that facility noise would be 43 dBA (id.). The Company indicated that the resulting nighttime ambient plus facility noise would be 44 dBA, and would therefore result in an L_{90} increase of 8 dBA at this location (id.).

With respect to noise increases at R-4B, the Town of Franklin asserted that the Company mis-applied the available ambient noise data in its analysis of projected noise increases at that location (Franklin Reply Brief at 8). Franklin argued that, in calculating the expected L_{90} increase at R-4B, the Company should have used the 35 dBA level measured at NML-3 rather than the 36 dBA level measured at NML-2, because NML-3 is closer to R-4B than is NML-2 (id.). Franklin therefore asserted that, based on measured ambient levels at NML-3, the L_{90} increase expected at R-4B would be 9 dBA -- a level which would exceed the maximum 8 dBA increase allowed under the Bellingham Special Permit (id. at 9).

The Company also provided estimated day-night sound levels ("L_{dn}"),[121] with and without the proposed facility, for the various residential and property line receptors (Exhs. HO-EN-17; HO-RR-75). The Company stated that, with the exception of location R-1, on Route 126, where the existing L_{dn} is 64 dBA, L_{dn} levels at all modelled receptors were currently at or near the 55 dBA threshold described in the Levels Document[122]

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120 The Company stated that the distance to this residence from the nearest point on the facility fenceline would be approximately 780 feet (Exh. HO-RR-85).

121 In response to an information request, the Company provided USEPA Document 550/9-74-004, entitled "Information on the Levels of Environmental Noise Requisite to Protect Public Health and Welfare With an Adequate Margin of Safety ("Levels Document") (Exh. HO-EN-1.1). In the Levels Document, L_{dn} is defined as the 24-hour A-weighted equivalent sound level, with a ten decibel penalty applied to nighttime levels (id. at Abb. 2). The Company explained that the nighttime penalty is intended to reflect the greater sensitivity of people to noise impacts at night (Tr. 13, at 24).

122 In the Levels Document, the USEPA recommends an outdoor L_{dn} level of 55 dBA or less for residential areas, and states that this level typically would prevent adverse (continued...)

(Exh. HO-RR-75). The Company estimated that at the most affected residence, location R-4B, the existing L_{dn} is 55 dBA, the estimated facility L_{dn} would be 49 dBA, and the estimated combined L_{dn} would be 56 dBA (id.).

The Company also stated that, at the property lines of the proposed facility, the highest 24-hour equivalent noise level ("L_{eq}") would be 58 dBA at location PL-2, on the west side of the proposed site (Exhs. HO-RR-75; HO-RR-65.1, App. F, at 41). The Company indicated that this level would be 17 dBA less than the 75 dBA limit recommended by USEPA to protect hearing, and 27 dBA less than the threshold level of the Occupational Safety and Health Administration for worker exposure over an eight-hour day (Exh. HO-RR-77.1, at 41).

The Company asserted that the proposed facility is being designed with careful consideration of measures to mitigate noise impacts to the surrounding community (Exhs. BEL-1, at 6-74; HO-RR-77.1, at 42; Tr. 13, at 5 to 6). The Company stated that its final acoustical design for the proposed facility would consider the application of several noise mitigation technologies including: (1) muffling of the gas turbine exhaust stream; (2) muffling in the gas turbine inlets, and enclosure of the inlet air ducts within the turbine buildings; (3) quiet air-cooled condensers and, if required, splitter mufflers to reduce fan noise; (4) heavier building walls to achieve adequate acoustic transmission loss for the turbine and gas compressor buildings; (5) acoustic louvers, if necessary, in ventilation intake openings in the east wall of the turbine building; (6) acoustic shrouds or partial enclosures around the exhaust ducts and HRSGs; and (7) silencing requirements for the circulating cooling water coolers (Exhs. BEL-1, at 6-74; HO-RR-77.1, at 42; Tr. 13, at 5 to 6, 48 to 59). By assuming a combination of the above measures in a facility design that would just meet the MDEP Standard at residential receptors, the Company derived a "baseline" cost figure of $7.45 million for mitigation of noise impacts from the proposed facility (Exh. HO-EN-19).

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[122](...continued)
effects on public health and welfare due to interference with speech and other outdoor activity (Exh. HO-EN-1.1, at 22).

The Company stated that it modified the original design of the proposed facility to comply with requirements of the Special Permit from the Bellingham ZBA, which limits the nighttime L_{90} noise increase at residential receptors to 8 dBA (Exh. HO-RR-30.1, App. 1, at 5; Tr. 13, at 5). The Company explained that additional reductions in facility noise at residences were accomplished by: (1) the acquisition of what would have been the closest residence, location R-4, to the east of the site; and (2) a modification to the plant layout involving the circulating cooling water coolers ("CCWCs") (Tr. 13, at 58-65). Specifically, the proposed facility would incorporate two smaller and quieter CCWCs instead of a single larger unit as initially proposed (id.). The Company stated that, pending the purchase of the residence in question, the incremental cost of the identified changes would be $150,000 for design changes involving the CCWCs, bringing the cost for noise mitigation at the proposed facility to $7.6 million (Exh. HO-RR-76).[123]

The Company offered testimony which described the conservative nature of its noise analyses, and stated that actual noise impacts from the proposed facility would be overestimated by the model due to worst-case assumptions with respect to: (1) meteorological conditions; (2) vegetative screening; and (3) ground reflectivity (Tr. 13, at 95-97). The Company's witness, Mr. Keast, stated that such conservatism likely would overstate the actual incremental L_{90} noise increase for some, and perhaps most of the time (id. at 97).

In response to requests from the Siting Board staff, the Company identified and considered the cost-effectiveness of various further measures for mitigation of noise impacts from the proposed facility, including design changes to the HRSGs or the ducts from the gas turbines to the HRSGs, the turbine building walls, and the air cooled condensers (Exhs. HO-EN-15; HO-EN-19). The Company considered two specific combinations of measures: (1) an option that would reduce the maximum projected nighttime L_{90} increase to 7 dBA at the nearest residence ("Option 1"), at an additional cost of approximately $3.0

[123] The Siting Board notes that the cost to the Company of acquiring the nearest residence and associated property remains unspecified, and therefore is not explicitly considered in this discussion.

million beyond the baseline, representing a 40 percent cost increase for noise mitigation[124] (Exh. HO-RR-76 (Rev.)); and (2) an option that would reduce the maximum projected nighttime L_{90} increase at the property lines to 10 dBA ("Option 2"), at an additional cost of approximately $10.7 million above baseline, representing a 144 percent cost increase (id.). The Company noted that Option 2 would require more stringent silencing methods as well as further modification of the plant layout, and asserted that this option would be of limited benefit given that affected lands abutting the property lines could not support any residential use (Exh. HO-EN-15).

The Company stated that it did not propose to incorporate either of these noise mitigation options into the pre-construction design of the proposed facility, but maintained that additional noise mitigation measures would be available for incorporation during final facility design to complete the overall noise control package for the proposed facility (Exh. HO-RR-77.1, at 42).

(2) Analysis

In past decisions, the Siting Board has reviewed the estimated noise impacts of proposed facilities for general consistency with applicable governmental regulations, including the MDEP's ten-dBA standard. Millennium Power Decision, EFSB 96-4 at 152; Berkshire Power Decision, 4 DOMSB at 403; Altresco-Pittsfield Decision, 17 DOMSC at 401. In addition, the Siting Board has considered the significance of expected noise increases which, although lower than 10 dBA, may adversely affect existing residences or other sensitive receptors. Millennium Power Decision, EFSB 96-4 at 152; Berkshire Power Decision, 4 DOMSB at 404; NEA Decision, 16 DOMSC at 402-403.

Here, the Company's analysis indicates that, for three residential receptors located to the north and east of the proposed site, facility operation would result in nighttime L_{90}

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124 Prior to the decision to acquire the residence at location R-4, the Company evaluated the option of a maximum increase of 7 dBA, assuming the continued presence of that receptor (Exh. HO-EN-19). Based on that circumstance, the Company estimated an additional cost of $3.6 million to limit the nighttime L_{90} increase to 7 dBA at location R-4 (id.).

increases of between six and eight dBA above existing ambient levels, which range from 35 to 36 dBA. During the day, facility operation would result in L_{90} increases of 5 dBA or less at all residential receptors. For the property line receptors to the northwest and west of the proposed site, which abut vacant industrially zoned land, nighttime L_{90} increases would be well above ten decibels and L_{90} increases would exceed the MDEP Standard along the west property line for the daytime period as well. At the east property line, a 3-dBA nighttime exceedance of the MDEP Standard is expected where the site abuts industrially zoned land which currently hosts a commercial use.

With respect to the proposed eight-dBA increase in nighttime L_{90} at the closest residence, the Siting Board notes that it previously considered and accepted a proposed increase of 8 dBA where nighttime ambient levels were low (31 to 33 dBA). Berkshire Power Decision, 4 DOMSB at 404. In that case, the Siting Board held that the proponent had demonstrated that the maximum contributions of facility noise to L_{dn} levels would be well below the USEPA 55-dBA guideline at residential receptors, and noted that overall noise levels were generally lower than the corresponding worst-case noise impacts in four other Siting Board reviews of gas-fired generating facilities. Id.

Here, nighttime ambient noise levels of 35 to 36 dBA are somewhat higher than in the Berkshire Power review. However, estimated nighttime noise levels with the proposed facility also would be generally lower than corresponding worst-case noise impacts in other Siting Board reviews of gas-fired generating facilities.[125]

The Siting Board agrees that ANP's proposed eight-dBA nighttime L_{90} increase would be consistent with increases accepted in recent reviews, and recognizes that the Company achieved such levels by undertaking specific noise mitigation efforts, including (1) appending additional buffering lands to its proposed site, and (2) reconfiguring certain noise producing components of the facility to reduce off-site noise impacts.

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125 The Siting Board also notes that, while the Berkshire Power project was to be water-cooled, the ANP-Bellingham's proposed facility would be air-cooled to help minimize water use.

With respect to the Town of Franklin's argument that the ambient noise level at R-4B is better represented by NML-3 than by NML-2, the Siting Board notes that although R-4B is situated generally between NML-2 and NML-3,[126] the 35 dBA ambient level measured at NML-3 may be the more appropriate level to use in calculating the estimated L_{90} increase at R-4B because its use would result in a more conservative estimate of impacts, and thereby would effectively capture in the analysis, the likely "worst-case" impact at that location. The Siting Board further addresses this issue, below, in its discussion of estimated (i.e., modelled) versus actual noise increases.

With respect to impacts of the proposed facility on L_{dn} noise, the Company has focused primarily on noise from the proposed facility alone, rather than on combined facility plus ambient noise. In a past review, the Siting Board cited concerns with an estimated combined L_{dn} of 59 dBA at affected residential receptors -- a level clearly over the 55 dBA USEPA guideline -- and based on that concern, limited L_{90} increases to no greater than 5 dBA. 1993 BECo Decision, 1 DOMSB at 108, 109, 114. Here the existing residential L_{dn} levels estimated by the Company are at or near the USEPA guideline at all residential receptors, except the relatively distant location R-1 on Route 126. Moreover, the Company has provided estimates showing that future L_{dn} levels would remain essentially unchanged with operation of the proposed facility. The Siting Board notes that here, as in other recent facility reviews where relatively quiet background noise levels were present at night, estimated contributions from the facility itself to overall residential L_{dn} levels would be significantly less than 55 dBA.

With respect to noise impacts at the site property lines, the record indicates that daytime L_{90} increases of up to 16 dBA would occur on vacant industrially zoned lands which abut the northwest and west property lines. The Company has demonstrated that the affected areas are not zoned to allow residential use, and also asserts that noise levels in such areas

126 The Town of Franklin cites a map (Figure 2) presented in the FEIR (Exh. HO-RR-65.1, App. F at 11) as its evidence that NML-3 is closer to R-4B than NML-2 (Franklin Reply Brief at 8). The Siting Board notes that the record contains no conclusive information with respect to the actual distances involved, or any differentials between the points in question.

would comply with OSHA regulations for worker safety and USEPA guidelines to protect hearing in non-residential areas. In previous reviews, the Siting Board has identified acquisition of additional lands or easements in affected areas as a means to mitigate off-site noise impacts. Berkshire Power Decision, 4 DOMSB at 405. The Siting Board notes that here, the proposed site is larger than several other generating facility sites recently reviewed by the Board, and that lands under the control of the proponent have been used with generally good effect to buffer abutting lands to the south and east of the project from property line noise increases that might otherwise have approached the MDEP ten-decibel standard.[127]

The record includes evidence regarding two options to further mitigate noise impacts from operation of the proposed facility; Option 1 which would reduce maximum nighttime L_{90} increases by one decibel to 7 dBA at the nearest residence, at a cost of $3.0 million; and Option 2, which would reduce property line impacts to meet the MDEP Standard, at a cost of $10.7 million. However, ANP-Bellingham has not proposed to implement options to further mitigate noise impacts from operation of the proposed facility, citing cost and limited effectiveness.

The Siting Board has found in several prior cases that incremental mitigation to reduce L_{90} noise impacts at residences was cost-justified. Millennium Power Decision, EFSB 96-4 at 156; Berkshire Power Decision, 4 DOMSB at 405, 442; Silver City Decision, 3 DOMSB at 367, 413. In Silver City, the Siting Board addressed proposed L_{90} increases of 10 dBA at affected residential receptors, and considered the cost-effectiveness of incremental mitigation measures that would result in decreased L_{90} impacts at those locations. Silver City Decision, 3 DOMSB at 357, 413. Here, the proponent already has taken steps to reduce the maximum L_{90} increase at a residential receptor from 10 dBA to 8 dBA, at an incremental cost of $150,000 plus the acquisition cost of the nearest residence (R-4). In addition, many of the Siting Board's prior decisions did not involve proposals for air-cooled technology, which, as the Siting Board previously has noted, can limit options for cost-effective noise mitigation,

127 See Section III.B.2.g, below, for a discussion of the Company's plans to assign approximately 92 acres of the site that would not ultimately be used for project facilities as conservation land that would be held by the Town of Bellingham.

but materially reduces other environmental impacts relating to water consumption, the visual impact of plumes from water cooling towers, and fogging and icing impacts from those plumes. Dighton Power Decision, EFSB 96-3 at 57; Berkshire Power Decision, 4 DOMSB at 345, 441. Finally, the record indicates that the incremental cost of reducing the L_{90} noise increase at the most affected residence to 7 dBA would be $3.0 million. Given that the maximum increase in L_{90} noise at residences already would be 2 dBA less than the MDEP Standard, and L_{dn} levels would remain close to the 55 dBA USEPA guideline, the record does not support incurring the added cost to achieve a further noise reduction of one decibel.

Consequently, the Siting Board finds that the incremental noise reductions that could be achieved through the incorporation of additional pre-construction mitigation measures in the project design would not result in cost-effective noise reduction benefits to the neighbors of the proposed facility, and therefore would not be consistent with minimizing costs. We also note that, consistent with the Siting Board's statutory mandate to minimize environmental impacts consistent with minimizing costs, it is appropriate to consider the overall environmental impact of the facility, and that the limited cost-effectiveness of further noise mitigation measures is in part attributable to the planned use of air-cooled technology, which the Siting Board previously has recognized to be of substantial and offsetting environmental benefit due to greatly diminished water consumption. Dighton Power Decision, EFSB 96-3 at 57; Berkshire Power Decision, 4 DOMSB at 345,441. The Siting Board therefore will not require additional noise mitigation beyond that already proposed by the Company.

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to operational noise would be minimized, consistent with minimizing cost.

With respect to construction noise impacts, the Siting Board agrees that adherence to the Company's proposed construction site practices concerning machinery and hours of operation, combined with the proposed mitigation of steam release events, would minimize construction related noise impacts. The Siting Board notes that the proposed steps would be consistent with approaches to construction noise mitigation that it has reviewed in recent generating facility cases. Therefore, the Siting Board finds that the environmental impacts of the proposed facility with respect to construction noise would be minimized.

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to noise would be minimized, consistent with minimizing cost.

Notwithstanding the foregoing acceptance of the proposed project design with respect to noise impacts, the Siting Board recognizes that noise issues, and specifically the accuracy of noise projections, are frequently a subject of particular concern to neighboring residents. Therefore, in order to alleviate public concern in this area, the Siting Board also finds that it would be appropriate to measure the noise impacts of operation of the proposed facility to verify the actual extent of L_{90} noise increases, and the degree of consistency with the 8.0 dBA maximum at residential receptors.[128] The Siting Board believes that noise monitoring in this case would serve two purposes: first, it would address concerns raised by intervenors regarding uncertainties inherent in noise modelling by confirming that the Company has actually achieved its projected noise levels; and second, it would provide information as to the accuracy of noise modelling that would be useful to the Siting Board in conducting future generating facility reviews.

Accordingly, ANP is directed to develop and implement a noise testing protocol to determine, at a date within one year of entering commercial operation, the actual L_{90} noise increases at the Maple Street residential receptors.[129] Such protocol should be consistent with the type of protocol used for testing compliance with the MDEP Standard, and should be conducted at, or as close as is practicable to, the Maple Street receptor locations identified in the Company's filing.

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128 In a past case, the Siting Board considered the predictive nature of acoustic science, and required noise testing to ensure that the actual noise impacts during facility operation were not materially higher than expected based on the pre-construction design projections. NEA Decision, 16 DOMSC at 402-403, 408. We note that such a requirement is consistent with the Siting Board's previously articulated policy objective of considering whether noise impacts will be "sufficiently small to avoid or minimize ... related complaints by residential or other abutters." Id.

129 As indicated by the Company, actual noise increases are likely to be lower than calculated based on modelling due to conservative model assumptions.

The Company is directed to provide a report to the Siting Board and the Town of Bellingham ZBA including: (a) a description of its noise testing protocol; (b) the results of its noise testing; (c) an assessment of any operating or maintenance factors, including weather conditions or equipment problems, that may have contributed to the result; (d) records of any complaints received concerning noise from the facility since start-up; and (e) any steps the Company plans to take, or has considered taking, to reduce plant noise. If noise testing indicates an actual L_{90} noise increase of greater than 8.0 dBA, the Company is further directed to assess options for such noise mitigation as would be required to bring the facility into compliance with the 8.0 dBA increase accepted by the Siting Board and the Town of Bellingham ZBA.

e. Traffic

(1) Description

The Company asserted that the construction and operation of the proposed facility at its proposed site would have negligible impacts on local traffic conditions (Exh. BEL-1, at 6-120). In support of its assertion, the Company provided traffic volume data for existing traffic conditions, and modelled future traffic conditions, with and without the proposed facility. The Company stated that its analysis included expected trip generation that would be attributable to the proposed facility, and estimated the impacts that would result from both facility construction and operation (id. at 6-98).

The Company indicated that existing peak commuter traffic periods in the vicinity of the proposed site are 7:00 a.m. to 8:00 a.m. and 4:45 p.m. to 5:45 p.m. (Exh. BEL-15, Vol. 1, at 5-2). The Company stated that, to estimate the traffic impacts on area roadways of construction at the proposed site, it assumed that all of the first shift of civil/construction workers would arrive during the morning peak period, and that all of those workers would depart during the evening peak (id.; Exh. BEL-1, at 6-108).[130] The Company indicated that these assumptions would result in a conservative estimate of traffic impacts because, in

130 The Company stated that the civil/construction shift would represent 200 workers requiring 180 vehicles (Exh. BEL-15, at 5-2). The Company indicated that it assumed an occupancy rate of 1.11 workers per vehicle to conservatively account for expected ride-sharing (id.).

actuality, shift changes at the proposed site would be generally outside of local peak hours (Exh. BEL-15, Vol. 1, at 5-2). The Company provided information regarding its planned work schedule during construction of the proposed facility, and indicated that the most intensive construction activity at the site would occur from months 12 to 17 of the planned 20.5 month construction schedule.[131] The Company stated that the maximum number of construction workers employed on the site at any one time could be up to 800 persons (id.).[132]

The Company presented a comparison of expected peak-hour levels of service ("LOS")[133] with and without the proposed facility for the two gateway intersections to the proposed site: (1) Route 126 and Maple Street to the north of the proposed site; and (2) Route 140 and Maple Street to the south of the proposed site (Exh. BEL-1, at 6-98; BEL-15, Vol. 1, at 5-1). With respect to existing traffic flow conditions at the two gateway intersections, the Company stated that during peak commuter periods, each of these unsignalized intersections operate with delays of greater than 120 seconds, and therefore are rated at LOS F for those periods (Exh. BEL-1, at 6-113).

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131 The Company stated that during the first 12 months of on-site construction activity, a single day shift would be present from 7:00 a.m. to 5:30 p.m. (Exh. BEL-30.1, at App. 1, exh. "A"). The Company stated that from months 12 to 17, a two shift program would be adopted for the mechanical and electrical trades, with shifts running from 6:00 a.m. to 4:00 p.m., and 4:00 p.m. to 12:00 a.m. (id.). The Company indicated that some weekend work could occur during this period in order to maintain the overall project schedule, but that project related traffic at the site likely would not conflict with the mid-day weekend peak hour (id.; Exh. HO-ET-2; Tr. 8, at 157-161).

132 As part of a Special Permit application before the Bellingham ZBA, the Company presented a proposed work schedule which indicates that approximately 200 civil/construction workers and approximately 600 first shift mechanical/electrical workers would be on-site concurrently, resulting in a maximum number of 800 workers that potentially would be on site at any one time (Exh. HO-RR-30.1, at App. 1, Exh. "A").

133 The Company stated that LOS is a measure of the efficiency of traffic flow at a location (Exh. BEL-1, at 6-102). The Company stated that traffic conditions on roadways and at intersections are represented by the letters A to F on the LOS scale, where A represents a "free flow" condition with minimal delays, and F represents "forced flow" or failing conditions with significant delays (id. at 6-103).

Based on its analysis of construction traffic volumes, the Company estimated that for the morning peak period in 1999, construction-related traffic would constitute between seven and 14 percent of total intersection volumes at the two gateway intersections (Exh. HO-ET-7). For the 1999 evening peak period, the Company estimated that between three and ten percent of total intersection volume at the gateway intersections would be attributable to construction activity at the proposed facility (id.).[134]

The Company also assessed peak hour LOS for the unsignalized intersection of the proposed site access driveway with Maple Street and projected that traffic conditions during construction would be acceptable (LOS B) for both morning and afternoon peak periods (Exh. BEL-1, at 6-109).[135]

The Company stated that it recognized that construction of the proposed facility would add additional traffic volume to areas that currently experience deficient traffic flow, and that it would mitigate such impacts by attempting to schedule shift changes so as to avoid local peak traffic periods, and by arranging with state and local authorities to provide uniformed officer controls at the affected intersections during the morning and afternoon shift changes (Exh. BEL-1, at 6-113). As an additional mitigating factor, the Company noted that a new commercial enterprise, Charles River Place ("CRP"), was currently under development in Bellingham near the junction of Route 126 and I-495, and that the proponent of that project had agreed to signalize the Maple Street/Route 126 intersection as mitigation for traffic impacts (id. at 6-105; HO-ET-5). The Company stated that, once signalized, traffic flow at

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134 The Company noted that the percentage of construction-related traffic at the gateway intersections would be greater between the hours of 4:00 p.m. and 5:00 p.m. (i.e., following the 4:00 p.m. shift change) than during the peak hour, but that overall intersection volumes would still be less than during the peak hour (Exh. F-RR-9).

135 The Company also indicated that the location of the intersection of the proposed access road with Maple Street would satisfy stopping sight distance requirements for both northbound and southbound approaches (Exh. HO-RR-46).

the Maple Street/Route 126 intersection would be improved to LOS B during the a.m. peak hour, and LOS C during the p.m. peak hour (Exhs. BEL-1, at 6-113; HO-ET-9.1).[136]

The Company indicated that, in addition to employee worker trips, there would be 45 delivery vehicle round trips per day during the peak construction period (Exh. BEL-15, Vol. 1, at 5-2).[137] The Company stated that deliveries of very large equipment and plant components would be scheduled for off-peak times and that the Company would coordinate such deliveries with state and local officials (Exh. BEL-1, at 6-108; Tr. 8, at 179-186). The Company stated that its EPC contractor, ABB, would be responsible for conducting road and bridge surveys to ascertain that adequate roadway widths, turning areas and bridge capacities would be present along its proposed delivery route (Exh. BEL-15, Vol. 1, at 5-7; Tr. 8, at 146-149). The Company indicated that the Maple Street/I-495 bridge would be the subject of a capacity study and that the Route 140/Maple Street intersection might require widening, but that a determination of the need for such roadway improvements would not be made until ABB completed its study prior to final placement of the EPC contract (id.; Exh. BCC-W-7).[138]

The Town of Franklin argued that because the ABB traffic study for the proposed project was incomplete, the Company had not adequately identified or described the traffic

136 The Company stated that the improvements proposed by the developer of CRP for Maple Street and Route 126 had not yet been effected, although CRP had been completed and recently had opened for business (Tr. 8, at 156-157). However, the Company confirmed, through conversations with Town of Bellingham officials, that said improvements are still planned for that intersection (Exh. HO-RR-47).

137 The Company stated that it assumed that the delivery trips would be distributed evenly throughout the 10-hour day, but that for conservatism in assessing impacts, five deliveries were assumed to occur during both the morning and afternoon peak periods (Exh. BEL-15, at 5-2).

138 The Company stated that, based on information available from ABB, the probable route for such deliveries would be from I-95 via Route 140 through the Towns of Foxborough, Wrentham, and Franklin to the junction with Maple Street (Exh. BEL-15, Vol. 1, at 5-7; Tr. 9, at 17-24). The Company also stated that if bridge improvements were required, no public money would be used (Company Brief at 165).

impacts to local roadways, including those in the Town of Franklin (Franklin Brief at 24). Franklin therefore asserted that the Company could not demonstrate that the traffic impacts of the proposed project would be minimized (id.). The Town of Franklin also expressed concerns that although roadways in Franklin, including Route 140, would figure prominently in the Company's plans to deliver equipment and labor to the proposed site, the Company had not yet approached the town regarding the matter (id. at 3, 23). However, the Company asserted that detailed permitting for traffic impacts typically occurs after the completion of the Siting Board's review and argued, citing Millennium and Berkshire, that the Siting Board previously had conditionally approved generating projects for which comprehensive traffic impact studies were pending (Company Reply Brief at 19).

In the process of developing approaches to mitigation for traffic as well as for other impacts, the Company stated its intention to form a liaison group consisting of local officials and residents that could include affected persons from Bellingham as well as from abutting towns, including the Town of Franklin (Tr. 8, at 81, 84). With respect to traffic impacts in particular, the Company stated that such a group likely would include representatives from each town through which traffic relating to project deliveries would travel (Tr. 9, at 22, 24).

With respect to traffic impacts from the proposed facility during operation, the Company stated that once the facility is fully operational, 16 employees would be on site during the day shift, and four employees would be on site during the night shift (Exh. BEL-1, at 6-117). The Company stated that, based on conservative projections of traffic impacts during facility operation, the proposed facility would have insignificant impacts on local traffic conditions, and that vehicle trips related to the proposed facility would constitute less than one percent of peak hour volumes at the gateway intersections (id. at 6-120). The Company asserted that no additional traffic mitigation would be necessary during operational lifetime of the proposed facility due to the expected low number of trips (id.).

(2) Analysis

The record indicates that there would be no change in LOS classification at the two identified gateway intersections near the proposed site as a result of either construction or operation of the proposed facility. However, the Siting Board notes that the intersections of Maple Street with both Route 126 and Route 140 currently exhibit poor traffic flow (LOS F) at peak travel times. Consequently, the Siting Board is concerned that although the LOS designation of the gateway intersections would not change with construction and operation of the proposed facility, the existing congestion at these already failing intersections likely would be exacerbated by traffic activity associated with the proposed project, particularly during the months of peak construction activity at the site.

To minimize traffic impacts from construction of the proposed facility, the Company has indicated that it would attempt to schedule shift changes outside of the identified local peak traffic hours, and would coordinate with state and local authorities to place uniformed officer controls at the intersection of Maple Street and Route 126, and the intersection of Maple Street and Route 140 during periods of maximum traffic flows relating to the proposed facility. The Siting Board agrees that such efforts would be consistent with those proposed and accepted in previous reviews of generating facilities.

The Company plans to schedule delivery of very large equipment and plant components for off-peak hours and intends to coordinate such deliveries with the appropriate state and local officials. However, the Siting Board is concerned that, regardless of scheduling, delivery of materials and equipment to the project site could affect traffic flow on area roadways, including Route 140. The Siting Board also notes that the Company is presently unable to identify a confirmed route for deliveries of very large plant components. We are concerned that if significant improvements to area roadways or bridges should be required to accommodate such deliveries, additional traffic impacts likely would result.

Therefore, the Siting Board directs ANP, in consultation with the MHD and the Towns of Bellingham, Franklin, Wrentham and Foxborough, to develop and implement a traffic mitigation plan which addresses intersection control, scheduling, and roadway and bridge construction.[139] With respect to intersection control, the Company is directed to coordinate with the appropriate authorities to place officer controls at unsignalized gateway intersections, and at other areas of concern as necessary, during the construction period. With respect to scheduling, the Company is directed to schedule, to the maximum extent practicable, arrivals and departures of construction related traffic, including but not limited to construction labor, deliveries of materials, equipment, and plant components, in a manner so as to avoid daily peak travel periods in affected areas. Such plans also should include steps to minimize traffic impacts associated with any roadway or bridge modifications, or other improvements, that may be required to effect delivery of large plant components.

Accordingly, the Siting Board finds that, with implementation of the foregoing condition, the environmental impacts of the proposed facility would be minimized with respect to traffic.

f. Safety

With respect to safety issues, ANP stated that to help insure safety at the proposed facility it would: (a) adhere to good engineering practice and comply with federal, state, and local regulations in its design, construction and operation activities; (b) require contractors to have programs in place to ensure compliance with applicable safety and health standards during construction; (c) incorporate into its construction contract provisions that require contractors to adhere to safety and health requirements; and (d) continually monitor operations on a regular basis (Exh. BEL-15, at 3-17; Tr.14, at 166).

In addition, the Company stated it would include within the facility the following design features to help insure safety: (a) containment basins or dikes for all hazardous material storage areas; (b) automatic shutdown systems with backup power supply for turbines and fuel supply systems; (c) emergency lighting; (d) adequate access for fire fighting vehicles and equipment; (e) fire retardant building materials and a self-sufficient fire

139 The Siting Board notes that, should delivery routes include roadways in towns other than those aforementioned, officials of those municipalities should be consulted in developing the traffic mitigation plan for the project.

protection system; and (f) fencing around the proposed site to prevent unauthorized individuals from gaining access to the facility (Exh. BEL-15, at 3-17 to 3-18).

(1) Materials Handling and Storage

ANP indicated it would store aqueous ammonia on site in two 14,000 gallon tanks, sitting side by side, and surrounded by a reinforced concrete dike (Exh. BEL-15, at 3-17). The Company stated that the transfer of ammonia from delivery vehicles would occur within a concrete diked containment area (id.; Tr.14, at 172). The Company also agreed to construct a single-roofed containment building enclosing the diked area and the dikes, but noted it would not completely seal the building in order to prevent pressure buildup (Exh. HO-RR-84; Tr. 11, at 77 to 78; Tr.14, at 174 to 176).

The Company provided computer modeling data which shows that the concentrations at the fence line from an ammonia spill would be 42 ppm after 30 minutes and 32 ppm after one hour, even without the containment building (Exh. HO-ES-1.1, at 2). The Company noted that these concentrations are below the Immediately Dangerous to Life or Health ("IDLH") threshold of 500 ppm (Exh. HO-RR-84). The Company stated that construction of the containment building would decrease the rate of evaporation of ammonia in the event of a spill and, depending on wind conditions at the time of the accident, could help reduce the concentration of ammonia at the fence line (Exh. HO-ES-1.1 at 2).[140]

The Company asserted that ammonia would be the only chemical delivered to the site via bulk shipments (Exh. HO-ES-6). All other chemicals would be delivered in small shipments via common carrier in approved Department of Transportation ("DOT") containers (id.). In addition, the Company stated that it would store chemicals on site in their DOT approved shipping containers whenever possible, and that the operators of the facility would

140 The analysis showed that if ambient wind speeds are low, the dispersion of ammonia vapor would be similar to the worst case calculated for the non-enclosed system. However, if ambient wind speeds are high, the emission rate will still be small, but the dilution will be higher and ambient concentrations should be lower (Exh. HO-ES-1.1, at 2).

store hazardous materials in a manner consistent with the Specific Material's Safety Data Sheet precautions (id.).

(2) Fogging and Icing

The Company used a fog model to assess whether the facility would cause ground level fogging or icing either during normal operations or during steam augmentation (Exh. HO-ES-8; Tr. 15, at 8-9). The modeling results indicated that fogging and icing would not occur under either scenario (Exh. HO-ES-8; Tr. 15, at 8-9).

(3) Emergency Response Plan

The Company indicated that it would develop an Emergency Response Plan ("ERP") and a Spill Prevention, Control and Countermeasure Plan ("SPCCP") similar to those found acceptable in previous Siting Board decisions (Exh. HO-ES-3).[141] The Company also stated that it would develop a separate contingency plan for the storage and handling of hazardous materials (Tr. 14, at 203). The Company indicated that it would develop these plans when the plant is completed (Exh. HO-ES-10; Company Brief at 171). In addition, the Company asserted that personnel trained in the ERP and SPCCP procedures would be on site at all times and that emergency response and spill prevention equipment would be continuously maintained at the power plant site (Exh. HO-ES-10).

(4) Analysis

The record demonstrates that the Company will manage, transport and store aqueous ammonia, and all other non-fuel chemicals, in accordance with applicable public and occupational safety and health standards. In particular, the Company's modeling results show that aqueous ammonia concentrations for the proposed facility, even in the event of a worst-case spill, would not exceed the IDLH standard at sensitive receptors located at or beyond the

[141] The Company states it will develop an emergency response plan similar to those found acceptable in Dighton Power Decision, EFSB 96-3, at 62; Berkshire Power Decision, 4 DOMSB at 416; and Cabot Decision, 2 DOMSB at 417.

fence line. In addition, the Company has agreed to further reduce ammonia concentrations by constructing a containment building around the dikes.

With regard to fogging, the record demonstrates that there will be no ground level fogging or icing resulting from cooling tower operations or steam augmentation.

With respect to chemical storage and handling, the record demonstrates that the Company has designed facilities for the proposed project to avert spills of hazardous materials. The Siting Board also notes that the Company intends to develop emergency procedures and response plans similar to those found acceptable in previous Siting Board decisions. The Siting Board encourages the Company to have applicable elements of its emergency response plan completed and filed with the Town before construction begins in order to cover possible contingencies related to construction accidents. In addition, the Siting Board encourages the Company to have trained personnel and equipment ready to address construction-related contingencies.

Accordingly, the Siting Board finds that, with the implementation of the safety measures described by the Company, the environmental impacts of the proposed facility would be minimized with respect to safety.

g. Electric and Magnetic Fields[142]

(1) Description

ANP indicated that operation of the proposed facility would produce magnetic fields associated with (1) the two new 345 kV lines which would interconnect the proposed project with transmission lines owned by New England Power Company ("NEPCo"), and (2) increased power flows on certain existing transmission lines (Exhs. BEL-15, at 9-8 to 9-13).[143] The Company indicated that the proposed facility would interconnect with NEPCo's

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[142] Electric fields produced by the presence of voltage, and magnetic fields produced by the flow of electric current, are collectively known as electromagnetic fields ("EMF").

[143] The Siting Board notes that NEPCo's and other utilities' existing transmission lines are not ancillary facilities as defined in G.L. c. 164, S 69G. However, in order to allow comprehensive analysis of environmental impacts associated with the construction and (continued...)

345 kV 303 line, which shares a right-of-way extending from the Beaver Pond substation to the West Medway substation with a 115 kV transmission line designated as the C-129 line ("303/C-129 ROW") (id. at 9-5).

The Company asserted that EMF levels from the 150 foot interconnect lines, which would be located entirely on the proposed site, would be negligible at the site boundary (Exh. BEL-15, at 9-5, 9-11; Exh. BEL 12.2). With respect to impacts on the transmission system along the 303/C-129 ROW, the Company indicated that the proposed project's operation would primarily affect power flow and associated magnetic fields extending north from the interconnection point to West Medway substation, although it also would affect power flows extending south to the Beaver Pond and Brayton Point substations (Exh. BEL 15, at 9-5). The Company explained that, under most regional generation dispatch scenarios, the proposed project would add approximately 500 megavolt-amperes of power flow to the preexisting flow on the 303 line north to West Medway substation (Exh. HO-RR-89S2, at 3). The Company also indicated that some shifts in preexisting power flow would occur, resulting in some increase in power flow on the adjacent C-129 line (Exh. HO-RR-32).

ANP provided calculations of magnetic field levels along the 303/C-129 ROW north of the interconnection point, both with and without operation of the proposed facility (Exhs. HO-RR-31; HO-RR-32). These calculations indicated that, under worst-case (light load) conditions, operation of the proposed facility would increase maximum magnetic field levels on the eastern edge of the ROW by approximately 18 milligauss ("mG"), to approximately 68 mG, and on the western edge of the ROW by 7 mG to approximately 13 mG (id.). The Company noted that these levels would be well below the 85 mG threshold which the Siting Board has previously recognized (Company Brief at 176). The Company added that, along the affected ROW segment north of the interconnection point, there are nine

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[143](...continued)

operation of the proposed generating facility, the Siting Board may identify and evaluate any potentially significant effects of the facility on magnetic field levels along existing transmission lines. See Millennium Power Decision, EFSB 96-4, at 170; Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

residences at or near the eastern edge of the ROW and three residences at or near the western edge of the ROW (Exhs. HO-EE-6, HO-EE-6.1).

ANP also provided information from the project interconnection study regarding transmission upgrades that may be required as a result of the proposed project, either alone or in combination with other projects (Exhs. HO-EE-14.1; HO-RR-89S2). The Company stated that reconductoring of the NEPCo 303 line between the site and West Medway substation would be required to accommodate the full 580 MW output of the proposed project (Exhs. HO-RR-27; HO-RR-89S2).

In addition, the Company indicated that, given the tendency for power to flow north on area transmission lines toward the West Medway substation, much of the project output would be carried beyond that point via various interconnecting regional transmission routes (Exh. HO-RR-89S2, at 3). The Company stated that combined increases in power flows from its proposed Bellingham and Blackstone projects would clearly require reconductoring segments of a 115 kV transmission line between the West Walpole and Needham substations, and might require reconductoring a 345 kV line in central Massachusetts and two additional 115 kV line segments in Rhode Island and central Massachusetts (id. at 5-10). In addition, if power flows from these two projects are considered in conjunction with the output of a 477 MW expansion of the Brayton Point generating station,[144] the project interconnection study indicates: (1) the need to reconductor a 345 kV line and three 115 kV line segments in eastern and central Massachusetts; and (2) the possible need to reconductor two additional 345 kV lines in central Massachusetts (Exh. HO-RR-27.1, at 23 to 24).

At the request of the Siting Board, the Company identified design measures that could be implemented as part of a transmission upgrade to reduce magnetic fields, and assessed the likelihood that these measures could be incorporated into the five upgrades that either would or might be required to interconnect either the proposed project alone, or both the ANP Bellingham and ANP Blackstone projects (Exhs. HO-RR-89S; HO-RR-89S2). The

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144 No proposal to expand the Brayton Point generating station has been filed with the Siting Board.

identified design measures included: (1) changing the phasing of adjacent transmission circuits; (2) changing the spacing of conductors on existing transmission structures; and (3) resuspending the conductors on structures of different design (Exh. HO-RR-89S).

The Company indicated that all the potential transmission upgrades likely would be accomplished by installing larger conductors on existing H-frame transmission structures (Exh. HO-RR-89S2). The Company therefore concluded that changes to either the conductor spacing or the structure design likely would not be feasible due to cost or engineering constraints (id.). The Company indicated that the remaining design measure -- changing the phasing of adjacent circuits -- may be applicable for the four known and potential upgrades which would involve lines on ROWs with multiple circuits (id. at 2-8).[145] The Company stated that it expects NEPCo, which would be responsible for those four transmission upgrades, to complete detailed facility designs by August 1, 1998 (id.). The Company indicated that it would encourage NEPCo and other transmission providers to incorporate prudent, cost-effective design measures that may reduce magnetic fields into any transmission upgrades required for the proposed project (Company Brief at 177, Exh. HO-RR-89S2, at 2-8).

(2) Analysis

In a previous review of proposed transmission line facilities, the Siting Board accepted edge-of-ROW levels of 1.8 kV/meter for the electric field and 85 mG for the magnetic field. 1985 MECo/NEPCo Decision, 13 DOMSC at 228-242. Here, off-site electric and magnetic fields would remain below the levels found acceptable in the 1985 MECo/NEPCo Decision.

Although consistent with edge-of-ROW levels previously accepted by the Siting Board, the estimated maximum magnetic fields along the 303/C-129 ROW with operation of the proposed facility -- approximately 68 mG at the eastern edge of the ROW and the nearest

145 These four upgrades include: (1) the 303 line north of the interconnection point, (2) the 302 line between Millbury and Carpenter Hill substations in central Massachusetts, (3) the W-175 line between Carpenter Hill and Palmer substations in central Massachusetts, and (4) a portion of the G-185 line between the Davisville tap and the West Kingston substation in Rhode Island (Exh. HO-RR-89S2, at 2-8).

residence -- are among the highest ever reviewed by the Siting Board, and represent a sizable increase above existing levels of approximately 50 mG.

The record does not include estimates of magnetic field changes related to the impact of project operation on sections of the transmission system other than the 303 and C-129 lines. The record does include evidence of the cumulative effect on power flow of adding approximately 1100 to 1500 MW of output from new projects, including the proposed project, interconnected to two 345 kV transmission lines extending south from the West Medway substation. Under most dispatch scenarios, much of this added output would be exported north or west from the West Medway substation, predominantly via key lines extending northwest to Millbury substation and beyond. A number of upgrades may be required along principal ROWs in central Massachusetts to accommodate the added output.

The Siting Board notes that, in past transmission line reviews, applicants have recognized that some members of the public are concerned about magnetic fields and for that reason, the applicants have incorporated design features into proposed transmission lines that would reduce magnetic fields at a low additional cost or no additional cost. See e.g., NEPCo Uxbridge Decision, 4 DOMSB at 148. The Siting Board has held that, as part of pursuing interconnection plans that require upgrades to the regional transmission system, generating facility applicants also should work with transmission providers to seek inclusion of practical and cost-effective transmission designs to minimize magnetic field levels along affected ROWs. Millennium Power Decision, EFSB 96-4, at 176; Berkshire Power Decision, 4 DOMSB at 421; Silver City Decision, 3 DOMSB at 353-354.

Here, the Siting Board notes that the Company has committed to request that NEPCo and other transmission providers consider potential magnetic field reductions and costs, as well as the feasibility, environmental impact and safety implications of different electrical phasing arrangements, in selecting the final design for required upgrades. However, the Company has indicated that cost and engineering considerations likely would lead the transmission provider to reuse, rather than replace, existing transmission structures, thus precluding changes to conductor spacing or structure design as part of the transmission upgrades. This limitation may significantly reduce opportunities to minimize magnetic fields.

In addressing a similar situation in a past review, the Siting Board encouraged consideration of alternative reconductoring designs on a localized basis, where residences are concentrated near an affected ROW, rather than for the entire circuit length requiring reconductoring. Millennium Power Decision, EFSB 96-4, at 176-177. While we recognize that significant costs could be involved in modifying or replacing even a few existing transmission structures, the Siting Board encourages ANP to work with NEPCo and other transmission providers to determine whether very localized changes to conductor spacing or structure design could provide a cost-effective means of minimizing project-related EMF increases near concentrations of residences.[146]

The Siting Board notes that the record in this case presents a broader range of EMF and transmission issues than in past Siting Board reviews of generating facilities. This is due in part to the higher output (580 MW) of the proposed facility, and in part to the cumulative nature of the transmission study submitted in this case, which reflects not just the proposed facility but also the proposed ANP Blackstone facility and the hypothetical expansion of the Brayton Point generating station. In addition, as has been the case in a number of previous reviews, the record is not complete as to the extent or design of required transmission upgrades and the related ability to minimize EMF impacts.[147]

The Company's commitment to work with NEPCo and other transmission providers is similar to that of previous generating facility applicants, and the Siting Board accepts that approach as meeting its standard of review for EMF. However, given the broad scale of

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146 The Siting Board notes the record does not establish whether transmission providers typically consider life cycle costs when selecting transmission upgrade designs. It is possible that such an analysis might demonstrate that the cost advantage of reusing existing transmission structures, rather than rebuilding or replacing them, is not as great as it would appear to be if only the initial installation costs were considered.

147 The Siting Board also is reviewing a proposal by IDC to construct a 1035 MW generating facility in Bellingham -- a potential project whose output is not reflected in the interconnection study for the proposed facility. It is unclear whether such additional output presents additional opportunities or constraints for the design of the transmission upgrades required for the proposed project, such that the transmission system as fully upgraded would be capable of accommodating cumulative power flow changes while also best minimizing magnetic field levels.

transmission upgrades potentially required for this and neighboring projects, and the associated significance of both the projects and the transmission upgrades for EMF levels in the region, the Siting Board seeks to remain informed as to the progress and outcome of transmission upgrade designs related to interconnecting the proposed project. Therefore, the Siting Board directs ANP to provide to the Siting Board with an update on the extent and design of required transmission upgrades, and the measures incorporated into the transmission upgrade designs to minimize magnetic field impacts, at such time as ANP reaches final agreement with all transmission providers regarding transmission upgrades.

Accordingly, the Siting Board finds that, (a) with the Company's pursuit of designs for upgrading the 303 line and other affected transmission lines that the Company and the transmission providers determine would best limit magnetic field increases at affected residences, and also be practical and cost-effective, and (b) with the Company's compliance with the condition to provide an update on required transmission upgrades and measures to minimize magnetic fields, the environmental impacts of the proposed facility would be minimized with respect to EMF impacts.

h. Land Use

(1) Description

The Company asserted that the development of the ANP Bellingham Energy Project at the proposed site would be compatible with current land use characteristics and zoning for the site, and would be consistent with the development objectives of the Town of Bellingham and the region (Exh. BEL-1, at 6-63). The Company further asserted that the proposed project would be compatible with surrounding uses and would be an economic benefit to the region during both construction and operation of the facility (id. at 6-64, 6-67).

The Company stated that the proposed facility is to be constructed in an industrial zone located west of Maple Street in Bellingham (Exh. BEL-1, at 6-64). The Company indicated that the 125-acre site is currently undeveloped and is generally wooded, except in the eastern portion where it is traversed by a 325 foot wide electric transmission line ROW (id. at 6-122). The Company noted that two high voltage transmission facilities, owned by NEP, are located within the existing ROW: the C-129 line (115 kV), and the 303 line (345 kV) (id.).

The Company stated that the proposed facility layout would require clearing of an approximately 20 acre upland portion of the site that is currently wooded (Exhs. BEL-1, at 6-58; HO-EL-10; Tr. 15, at 56). The Company also indicated that approximately seven additional acres along the western edge of the NEP ROW, and adjacent to the proposed facility footprint, would be temporarily cleared to facilitate construction activity and to provide space for construction parking and materials laydown areas (id. at 6-58; Exh. EC-2 (Rev.); Tr. 15, at 56-58, 99-103). The Company indicated that, subject to agreements with NEP and the Bellingham Conservation Commission, it intended to replant certain cleared portions of the site after completing construction of the proposed facility, including the built-up slopes to the southwest of the plant, and portions of the NEP ROW, except in the immediate vicinity of the electrical tie-in for the project (Exhs. HO-EL-10; HO-EC-2 (Rev.); Tr. 15, at 57-58, 99-103).

The Company described the land uses contiguous to the proposed site as the aforementioned utility easement and commercial and residential uses to the east and south, vacant land including wetlands associated with the Charles River to the north, and an interstate highway ("I-495") to the west (Exh. BEL-1, at 6-63). The Company also indicated that new commercial development, including a cinema complex, was under construction to the northwest of the site near the intersection of I-495 and Route 126 (id.; Exh. HO-RR-44). Based on 1991 land use data available from the Massachusetts Geographic Information System Office ("MassGIS"), the Company estimated that 77 percent of the area within a one-mile radius of the proposed site is open or agricultural land, 18 percent is devoted to residential uses, and 5 percent is used for commercial or industrial purposes, including I-495 (Exh. HO-EL-3). Within a half-mile radius of the proposed site, the Company estimated that

79 percent of the land is open or agricultural, 14 percent is residential, and 7 percent is used for industrial or commercial purposes (id.).[148]

The Company stated that its proposed facility would be buffered from nearby uses by distance and natural features, including wetlands, as well as by surrounding developed uses, including I-495 and the NEP ROW (Exh. BEL-1, at 5-58, 5-63). Furthermore, the Company indicated that, pursuant to its PILOT agreement with the Town of Bellingham (See Exh. HO-V-23.1), it would convey to the town as "restricted open space" approximately 92 undeveloped acres of the site that would then be preserved and maintained by the Town as conservation land (Exhs. BEL-15, Vol. 1, at 10-24; HO-EL-15; HO-V-23; HO-EL-17).

The Company indicated that most of the residential uses in the vicinity of the site are located along Maple Street and adjoining streets to the east and north of the site which extend further easterly across the town boundary into the Town of Franklin (Exh. BEL-1, at 6-63 to 6-65). The Company stated that presently, the closest residence is located 330 feet to the east of project property line; however, the Company explained that the residence is located on property that would be acquired by the Company to accommodate its proposed access road (Exhs. HO-EL-2; BEL-12.2; Tr. 15, at 72 to 73). The Company therefore asserted that, post construction, the closest residence would be located on the west side of Maple Street approximately 780 feet from the nearest facility fenceline, and approximately 470 feet south of the nearest project feature, a storm water basin located adjacent to the intersection of the proposed facility access driveway with Maple Street (Exh. HO-RR-85). The Company added that, as mitigation for potential impacts to residential property values in the vicinity of the proposed facility, it had offered a Property Compensation Program that would be available to residents within one half mile of the proposed site (Company Brief at 179).

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148 The Company asserted that it used various ground-truthing techniques to confirm the validity of the MassGIS data for 1998 conditions. The Company provided recent aerial photos of the site which included the surrounding areas, and submitted an exhibit which highlighted areas where, based on reconnaissance of the local area by its consultant, land use characteristics within 1.25 miles of the proposed facility were found to have changed since 1991 (Exhs. HO-EL-1.1, HO-RR-41.1).

The Company stated that it identified a total of 53 residences within one half mile of the proposed facility, and that it identified 322 residences that would be located within one mile of the project (Exh. HO-EL-2).[149] The Company indicated that the nearest undeveloped land that potentially would be available for residential development would be located 780 feet to the northeast of the proposed project's fenceline (Exh. HO-EL-4).[150]

Mr. Brady, a witness presented by intervenor Goulart, testified regarding his own land use analysis which found a significantly larger number of Franklin residences located within one mile of the proposed facility. Mr. Brady stated that the analysis used property assessment data supplied by the Town of Franklin to determine that 671 Franklin residences would be located within one mile of the proposed site (Exhs. ANP-JAG-1.10 C; ANP-JAG-8; Tr. 14, at 119-125). Mr. Brady therefore argued that the Company had underestimated the mix of residential land uses that exist in proximity to the proposed site, particularly with respect to areas in Franklin (JAG Brief at 5). The Company responded that it had accurately characterized the land uses within one mile of the proposed site and argued that Mr. Brady was unable to specify the location of the center-point used to define the area of Franklin that was the focus of his analysis (Company Brief at 180). The Company therefore asserted that the data introduced by Mr. Brady could not be verified, and hence was unreliable (id.).

The Company stated that the proposed site is located within the industrial zone, and that its proposed facility is a permitted use under this zoning category (Exh. BEL-1, at 6-64). The Company indicated that in order to comply with all Town of Bellingham zoning restrictions, it would secure special permits from the Zoning Board of Appeals ("ZBA") relative to four specific issues: (1) standard height restrictions, (2) air emissions, (3) on-site

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149 The Company stated that it identified the areas located within one mile of the proposed facility by selecting a central point within the footprint of the proposed facility from which to describe a circle having a radius of one mile (Tr. 15, at 26).

150 The Company identified the subject parcel from assessors maps as Map 26, Lot 4, and noted that this 'suburban' zoned parcel has an existing residence closer to its frontage with Maple Street (Exhs. HO-EL-4; BEL-12.2, Tr. 15, at 81-91). In its Brief, the Company asserted that the identified lot is non-conforming, and that the existing residence therefore represents the maximum development potential of that parcel (Company Brief at 189).

storage and use of hazardous materials and waste, and (4) use of temporary structures and authorization for parking of light and heavy commercial vehicles at the site during the construction period (Exhs. HO-EL-6.1, at Tab 2; HO-EL-9).[151] The Company indicated that effective February 5, 1998, it had received conditional approvals from the Bellingham ZBA with respect to each of the four special permit applications (Exh. HO-RR-30.1). The Company indicated that it had not yet filed its Site Plan with the Town of Bellingham Planning Board, but that it intended to do so in May of 1998 (Tr. 15, at 45).

With respect to impacts to wildlife species and habitats at the proposed site, the Company stated that, based on its initial consultation with the Massachusetts Natural Heritage and Endangered Species Program ("NHESP"), no species of special concern or significant habitats were identified in the vicinity of the proposed site (Exh. BEL-1, at 6-57). The Company also stated that there were no known rare plants, animals, or exemplary communities in the project area (id.). However, the Company noted that three wetland areas located within the site boundaries contained features that were consistent with "vernal pool habitat" as defined in the Wetlands Protection Act regulations (310 CMR 10.04), and stated that it subsequently identified and described those features in documentation submitted to NHESP and in its Wetland Notice of Intent (See Exh. BCC (2)-W-5.1) for the project (id.; Exh. BCC-W-11; Tr. 11, at 68-74). In addition, the Company stated that a spotted turtle, a "species of special concern" in Massachusetts, had been discovered during a survey of the proposed site (Exh. BEL-1, at 6-57).

The Company stated that none of the identified vernal pool habitats would be located within the project footprint area, and indicated that it had developed a set of mitigation measures specific to the presence of spotted turtles at the site including: (1) education of project personnel in the identification of the spotted turtle; (2) fencing and barriers to prevent

151 The Company stated that its Special Permit Application concerning construction issues initially included a request for authorization to remove earth from the project site during construction (Tr. 15, at 75). The Company subsequently indicated that it had withdrawn its permit request for earth removal after determining that its proposed activities would not meet the applicable threshold (id.). The Company further indicated that it did not intend to remove excavated materials from the site (Exh. HO-EL-9).

movement of turtles into construction areas; (3) daily inspections for, and relocation of, turtles away from construction activity; and (4) restoration of disturbed areas following construction to establish conditions that would be adequate for turtle migration and nesting (Exh. BCC (2)-W-5.1, at 2-6 to 2-12, and 3-6; Tr. 12, at 72-74). The Company asserted that these measures would prevent adverse short-term and long-term impacts to the spotted turtle and its habitat during both construction and operation of the proposed facility (id.; Tr. 15, at 104-107).[152]

The Company indicated that an initial survey for historic and archaeological resources found the proposed site to be of low to moderate sensitivity with respect to such resources (Exh. BEL-15, Vol. 1 at 13-4). The Company stated that the Public Archaeology Laboratory, Inc. ("PAL"), under the direction of the Massachusetts Historical Commission ("MHC"), performed a site examination to further characterize any historic or archaeological resources at the proposed site and concluded that the site did not meet eligibility criteria for listing in the National Register of Historic Places (id. at 13-1). MHC therefore determined that no additional archaeological investigation of the site is warranted (Exhs. HO-EL-13; HO-EL-13.1; April 9 MHC letter to MEPA).

With respect to off-site impacts associated with construction of utility interconnects for the proposed project, the Company stated that the gas supply interconnect would consist of a 1.11 mile natural gas pipeline that would be constructed, owned and operated by AGT. The interconnect currently is the subject of a separate proceeding before the FERC (Docket CP98-100-000).[153] The Company indicated that the preferred route for the gas pipeline would require temporary and permanent clearing of both upland and wetland woods along a new easement (Tr. 15, at 58-63). The Company stated that a permanent easement covering 5.08

[152] The Company also noted that, by virtue of its documentation of the vernal pool habitats present on the proposed site, those areas eventually would become certified by the State under the Wetlands Protection Act (Tr. 15, at 103-104).

[153] On December 23, 1997, the Siting Board intervened in CP98-100-000.

acres would be required for the pipeline, within which 3.36 acres of upland woods, and .02 acres of wetland woods, would be cleared and maintained free of woody vegetation[154] (id. at 60). The Company asserted that the FERC review would ensure that the environmental impacts of the gas pipeline interconnect would be minimized consistent with FERC standards (Company Brief at 137). (See Section III.B.2.b.(1) above, for a discussion of wetland impacts related to the AGT pipeline).

Finally, the Company stated that water and sewer interconnects for the proposed facility would be co-located with the project access driveway, and that therefore, no incremental impacts would result from the construction of those facilities (id. at 59 to 60).

(2) Analysis

As part of its review of land use impacts, the Siting Board considers whether a proposed facility would be consistent with state and local requirements, policies, or plans relating to land use and terrestrial resources. Here, the record indicates that the proposed site and surrounding areas on three sides are zoned for industrial use, and that abutting areas are a mixture of vacant, residential and commercial uses. The record further indicates that the area within one half mile of the proposed site is predominantly open land, with approximately 20 percent being used for residential or commercial purposes.

The proposed facility is an allowed use under the zoning by-laws of the Town of Bellingham. The Siting Board notes that the proposed stacks and other facility structures would be considerably taller than existing structures in the area, but that the project proponent has received conditional approval of its four Special Permit applications before the

[154] In its environmental comments to the FERC, the Siting Board noted that for the majority of its length, AGT's proposed pipeline would parallel the existing NEP transmission ROW, and would make use of already cleared portions of that ROW to facilitate construction activity (Environmental Comments of the EFSB in Docket CP98-100-000, March 20, 1998). However, the Siting Board recommended a route variation to minimize wetlands impacts and sought the development of a revegetation and management plan for the ROW, and mitigation measures to address possible impacts to spotted turtle habitat (id.).

Bellingham ZBA to construct the facility with building heights and other characteristics as currently proposed.

The Company has adequately considered the impacts of the proposed facility with respect to wildlife species and habitats and historic and archaeological resources.[155] Moreover, the Siting Board notes that the proposed project will undergo additional reviews by other authorities with respect to these issues including a 401 Water Quality Certificate, and an Order of Conditions to be issued by the Bellingham Conservation Commission.

The Siting Board has considered the adequacy of site buffering and proposed mitigation to limit the visual and noise impacts of the proposed facility in Sections III.B.2.d and III.B.2.e, above. Further, the Siting Board has imposed conditions with respect to visual and noise impacts of the proposed facility in Sections III.B.2.d and III.B.2.e, above, and notes that these conditions address, to a significant degree, the issue of consistency with land use objectives.

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

3. Cost

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine if an appropriate balance has been achieved between environmental impacts and costs.

The Company stated that the total cost of the proposed facilities at the proposed site would be $300 million in 2000 dollars (Exh. HO-C-1; Tr. 11, at 4-5). The Company stated that this cost estimate reflects current site specific estimates of: (1) construction costs;

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155 The Siting Board notes that, in a letter dated April 9, 1998, the MHC advised MEPA of its finding that no further archaeological testing is necessary at the proposed site. However, MHC indicated that its review of areas that would be traversed by AGT's proposed gas pipeline was ongoing.

(2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance[156]; (4) site acquisition costs; and (5) licensing and development costs (id.). The Company asserted that the cost estimate was realistic for a facility of this size and design based on the Company's knowledge of costs for similar projects (Company Brief at 196).

The Company also considered the relative costs of several options to minimize further certain environmental impacts associated with the proposed facility, including options to reduce facility water use through alternatives to steam augmentation, and options to increase noise mitigation. With respect to the proposed use of steam augmentation to provide 40 MW of peak capacity, the Company presented heat rate information indicating its proposed peaking operations would show a heat rate increase (efficiency loss) of 24 percent above that for baseload operation at the proposed facility, as compared to a relative heat rate for new stand-alone simple cycle peaking capacity of 44 to 64 percent above that for baseload operation at the proposed facility (Exh. HO-RR-72R). As further evidence of the economic merits of its proposed use of steam augmentation, the Company maintained such operation would require only minimal additional piping equipment, with essentially no added capital cost and no effect on baseload operating cost (Exh. HO-EW-8). With respect to alternatives, the Company maintained that: (1) an alternative peaking design to allow supplemental firing of the HRSG would require larger air-cooling condensers and redesign of the steam turbine, with loss of baseload operating efficiency; (2) an alternative peaking design to reduce the gas turbine air inlet temperature would require a chilling plant, with a loss of baseload operating efficiency due to increased pressure drop in the gas turbine air inlet; and (3) alternative stand-alone peaking capacity would involve substantial capital costs, as well as the less favorable heat rate during peaking operations, discussed above (Exh. HO-RR-65.1, at 3-36 to 3-37; Tr. 11, at 103-104).

As noted above in Section III.B.2.d, the Company indicated that noise mitigation technology to further reduce the noise impacts at the most affected residential and property line noise receptors would cost: (1) an additional $3.0 million to limit the noise increase over

156 The Company indicated the contingency allowance covers CO_2 mitigation and the total capital costs include NO_x offset costs (Tr. 11, at 4-5).

In Section III.B.2.b, above, the Siting Board examined the trade-offs between air quality, water supply, visual impacts and cost associated with the use of steam augmentation, and based on our analysis of the trade-offs and the proposed mitigation for water supply impacts, concluded that the water supply impacts of the proposed facility would be minimized with use of steam augmentation.

In Sections III.B.2.d, above, the Siting Board examined the trade-offs between noise and cost associated with identified noise mitigation options, and found that, with the implementation of proposed mitigation, the environmental impacts of the proposed facility with respect to noise would be minimized, consistent with minimizing cost.

In Section III.A, above, the Siting Board found that ANP has considered a reasonable range of practical facility siting alternatives.

Therefore, the Siting Board finds that, with the implementation of the conditions set forth in Sections III.B.2 above, (1) the proposed facility would be sited, designed and mitigated in a manner that minimizes environmental impacts and costs, and (2) an appropriate balance would be achieved among conflicting environmental concerns as well as between environmental impacts and cost.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with the current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Section II.A, above, the Siting Board has found that the Company has established need for the proposed project. Further, in Sections II.B and II.C, above, the Siting Board has found that the proposed project is superior to all alternative technologies reviewed with respect to providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost, and that upon compliance with the listed conditions, ANP has established that its proposed project is reasonably likely to be a viable source of energy. In Section III.A, above, the Siting Board has found that ANP has considered a reasonable range of practical facility siting alternatives. In Section III.B, above, the Siting Board has found that with implementation of the listed conditions relative to air quality, water supply, visual impacts, noise, and traffic, the proposed facility would be sited, designed and mitigated in a manner that minimizes environmental impacts and costs, and an appropriate balance would be achieved among conflicting environmental concerns as well as among environmental impacts and cost.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.C, and III.B, above, and listed below, the construction and operation of the proposed facility will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Sections III.A and III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs relating to air quality, water supply, water-related discharges, wetlands protection, noise, rare and endangered species, and historical preservation. As evidenced by the above discussions and analyses, the proposed facility will be generally consistent with identified requirements under all such programs.

Accordingly, the Siting Board APPROVES the petition of ANP Bellingham Energy Company to construct a 580 MW bulk generating facility and ancillary facilities in Bellingham, Massachusetts subject to the following conditions during construction and operation of the proposed facility:

(A) In order to ensure that the project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives, the Siting Board directs ANP to provide: (1) a copy of a signed EPC contract between ANP and ABB or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPCo providing the proposed project with access to the regional transmission system.

(B) In order to mitigate CO_2 emissions, the Siting Board requires ANP to provide CO_2 offsets through a total contribution of $620,690, to be paid in five annual installments during the first five years of facility operation, plus a contribution of $35,100 in the first year of facility operation as an offset for on-site tree clearing, to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff. If the Company chooses to provide the entire donation within the first year of facility operation, the CO_2 offset requirement would be a total contribution in the amount of $503,040 to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff.

(C) In order to minimize impacts to water resources, the Siting Board directs the Company to work with Charles River Watershed Association to ensure periodic documentation of program activities and results to the Company, and to share periodic reports with Town of Bellingham officials and the Siting Board.

(D) In order to minimize visual impacts, the Siting Board directs the Company, consistent with the directives in Section III.B.2.c, to provide reasonable off-site mitigation of visual impacts, including shrubs, trees, window awnings or other mutually-agreeable measures, that would screen views of the proposed facility at properties along Maple Street, and at other locations within one mile of the proposed facility, as requested by residents or appropriate municipal officials. In this regard, the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to public officials in Bellingham and Franklin and to all affected property owners prior to the commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement plantings as necessary to ensure that healthy plantings become established.

(E) In order to alleviate public concern, the Siting Board requires the Company to provide a report to the Siting Board and the Town of Bellingham ZBA including: (a) a description of its noise testing protocol; (b) the results of its noise testing; (c) an assessment of any operating or maintenance factors, including weather conditions or equipment problems, that may have contributed to the result; (d) records of any complaints received concerning noise from the facility since start-up; and (e) any steps the Company plans to take, or has considered taking, to reduce plant noise. If noise testing indicates an actual L_{90} noise increase of greater than 8.0 dBA, the Company is further directed to assess options for such noise mitigation as would be required to bring the facility into compliance with the 8.0 dBA increase accepted by the Siting Board and the Town of Bellingham ZBA.

(F) In order to minimize traffic related impacts, the Siting Board requires the Company, in consultation with MHD and the Towns of Bellingham, Franklin, Wrentham and Foxborough, to develop and implement a traffic mitigation plan which addresses intersection control, scheduling, and roadway and bridge construction.[157] With respect to intersection

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157 The Siting Board notes that, should delivery routes include roadways in towns other than those aforementioned, officials of those municipalities should be consulted in developing the traffic mitigation plan for the project.

control, the Company is directed to coordinate with the appropriate authorities to place officer controls at unsignalized gateway intersections, and at other areas of concern as necessary, during the construction period. With respect to scheduling, the Company is directed to schedule, to the maximum extent practicable, arrivals and departures of construction related traffic, including but not limited to construction labor, deliveries of materials, equipment, and plant components, in a manner so as to avoid daily peak travel periods in affected areas. Such plans also should include steps to minimize traffic impacts associated with any roadway or bridge modifications, or other improvements, that may be required to effect delivery of large plant components.

(G) In order to provide the Siting Board with final design information relating to minimization of EMF impacts, the Siting Board directs ANP to provide an update on the extent and design of required transmission upgrades, and the measures incorporated into the transmission upgrade designs to minimize magnetic field impacts, at such time as ANP reaches final agreement with all transmission providers regarding transmission upgrades.

Because issues addressed in this decision relative to this facility are subject to change over time, construction of the proposed generating facility and ancillary facilities must be commenced within three years of the date of this decision.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

M. Kathryn Sedor

M. Kathryn Sedor
Hearing Officer

Dated this 18th day of August 1998

TABLE A-1
PERMITTED WITHDRAWAL VOLUMES, ACTUAL AVERAGE DAILY WATER USE
AND TOTAL ANNUAL WATER USE BY BASIN, TOWN OF BELLINGHAM, 1993-1996

	Well #	Permitted Approved Daily Volume	1993		1994		1995		1996	
			Total	Daily Average	Total	Daily Average	Total	Daily Average	Total	Daily Average
Blackstone River Basin	No. 1	0.52	93.2	0.26	97.52	0.27	97.3	0.27	90.54	0.25
	No. 2	0.36	9.8	0.03	0	0	0	0	19.84	0.05
	No. 3	0.65	65.9	0.18	57.16	0.16	40.46	0.11	45.37	0.12
	No. 4	0.52	145.3	0.40	105.33	0.29	158.92	0.44	147.56	0.40
	No. 11	0.36	92.1	0.25	91.35	0.25	95.44	0.26	63.75	0.17
Basin Subtotal:		2.41	406.30	1.11	351.36	0.96	392.12	1.07	367.06	1.01
Percent of System Total:		51%	68%	68%	54%	54%	61%	61%	65%	65%
Charles River Basin	No. 5	0.29	82.1	0.22	100.04	0.27	81.77	0.22	68.13	0.19
	No. 7	0.61	39.2	0.11	104.29	0.29	67.67	0.19	35.48	0.10
	No. 8	0.90	70.9	0.19	99.27	0.27	97.88	0.27	95.79	0.26
	No. 12	0.50	0	0	0	0	0	0	0	0
Basin Subtotal:		2.30	192.20	0.53	303.60	0.83	247.32	0.68	199.40	0.55
Percent of System Total:		49%	32%	32%	46%	46%	39%	39%	35%	35%

All values in millions of gallons

TABLE A-2

RELATIONSHIP BETWEEN RECHARGE AND WITHDRAWAL RATES, BY AQUIFER, BELLINGHAM, MA, 1993-1996

Wells	Zone II Area (sq. mi.) A	Precipitation Recharge per Sq. Mi. (mgd) B	Total Recharge from Precipitation C (=A x B)	Ave. Aquifer Withdrawal 1983-1996 (mgd)
No. 5	0.52	1.0	0.52	0.23
No. 12	1.18	1.0	1.18	0
No. 7, 8	1.85	1.0	1.85	0.42
No. 1, 2, 3, 4, 11	3.68	1.0	3.68	1.04

TABLE A-3

SUBBASIN LOW-FLOW DATA AND
CONTRACTED SUMMER PROJECT WATER USE,
TOWN OF BELLINGHAM, STANDARD RATES

Subbasin	7Q10 Flow (mgd)	Average Summer Flow (July-Sept.) (mgd)	Summer H2O Use, ANP-Bellingham, Std. Rates
Charles - Millis	9.4	34.3	0.05
Blackstone - Woonsocket	65.3	212	0.05
Blackstone - Peters Brook*	0.45	No data	0.05

* Flows and project water use data for Peters Brook are subsumed in the data for Blackstone - Woonsocket.

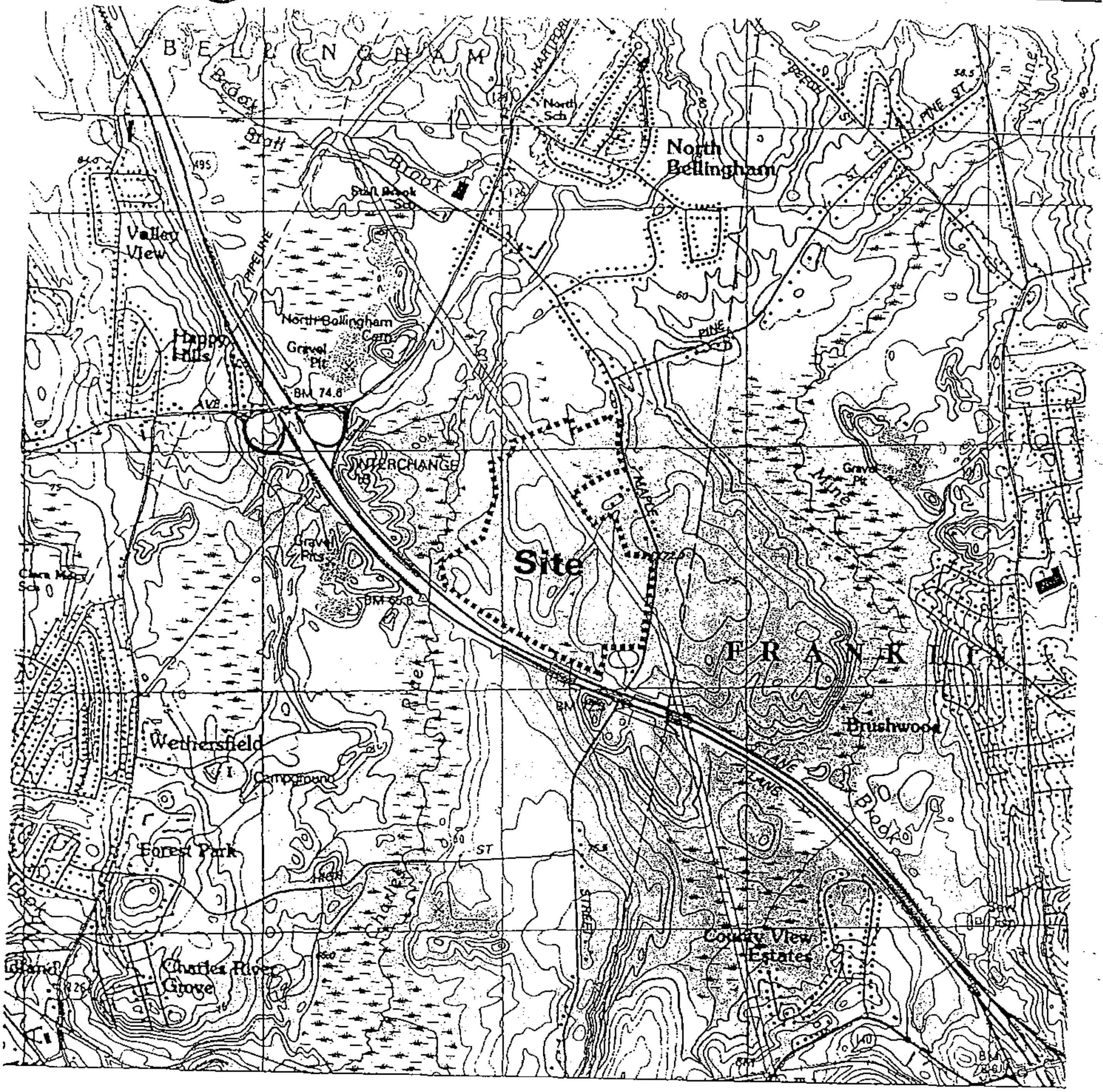
APPROVED by the Energy Facilities Siting Board at its meeting of August 13, 1998, by the members and designees present and voting: Janet Gail Besser (Chair, EFSB/DTE); W. Robert Keating (Commissioner, DTE); James Connelly (Commissioner, DTE); Sonia Hamel (for Trudy Coxe, Secretary of Environmental Affairs); and David O'Connor (for David A. Tibbetts, Director of Economic Development).

Janet Gail Besser

Janet Gail Besser, Chair
Energy Facilities Siting Board

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).



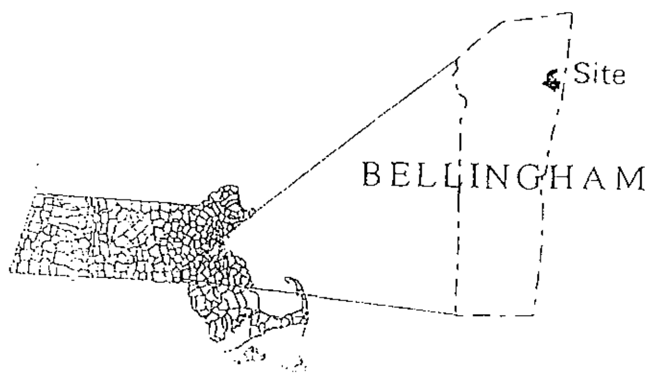


Figure 1
Site Location

Scale 1:24000

0 2000 4000

Feet

Data supplied by Massachusetts EOEA, MassGIS

Date: 08 May 97 14:07:48 Monday
/usr2/anp/drqeilal.map

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Cabot Power Corporation for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 91-101A

FINAL DECISION

Peter M. Palica
Hearing Officer
October 9, 1998

On the Decision:

Barbara Shapiro

APPEARANCES: David S. Rosenzweig, Esq.
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Petitioner

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Intervenor

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Interested Person

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Chelsea, Massachusetts 02150
Interested Person

Eric Gross
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Chelsea, Massachusetts 02150
FOR: Eleven Chelsea Residents
Intervenor

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

Abbreviation	Explanation
AALs	Annual allowable ambient limits
Act	Massachusetts Electric Restructuring Act of 1997
BACT	Best available control technology
BECo	Boston Edison Company
Btu	British Thermal Units
CAAA	Federal Clean Air Act Amendments of 1990
CPC	Cabot Power Corporation
CELT	Capacity, Energy, Loads and Transmission (yearly reports prepared by NEPOOL)
City of New Bedford	City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992)
CO	Carbon monoxide
CO_2	Carbon dioxide
Company	Cabot Power Corporation
Daniels	Daniels Printing, Limited Partnership
dBA	A-weighted Decibel
DCR	Debt coverage ratios
$/kW	Dollars per kilowatt
DOMAC	Distrigas of Massachusetts
DSM	Demand side management

EFSB	Energy Facilities Siting Board
EMF	Electric and magnetic fields
EPC	Engineering, procurement, and construction
ERCs	Emission reduction credits
ERP	Emergency Response Plan
Everett	City of Everett, Massachusetts
FERC	Federal Energy Regulatory Commission
gpd	Gallons per day
HRSG	Heat recovery steam generator
IEIP	Island End Industrial Park
kJ	Kilojoule
kV	Kilovolt
L_{90}	The level of noise that is exceeded 90 percent of the time
LAER	Lowest Achievable Emission Rate
L_{eq}	24-hour equivalent noise level
LNG	Liquified natural gas
LOS	Level of service -- a measure of the efficiency of traffic operations at a given location
MCP	Massachusetts Contingency Plan
MCZM	Massachusetts Coastal Zone Management
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company

MMBtu	Million British thermal units
MW	Megawatt
NAAQS	National ambient air quality standards
NEA	Northeast Energy Associates
NEPCO	New England Power Company
NEPOOL	New England Power Pool
1994 Cabot Decision	Cabot Power Decision, EFSB 91-101, 2 DOMSB 241 (March 9, 1994)
Notice	Notice of Adjudication and Public Hearing
NOx	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NU	Northeast Utilities
NUG	Non-utility generator
Original Project	Reference to EFSB 91-101
O&M	Operation and maintenance
Pb	Lead
PM-10	Particulates
PPAs	Power purchase agreements
PSD	Prevention of significant deterioration
PURPA	Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3
QF	Qualifying facility

ROW	Right-of-way
SCR	Selective Catalytic Reduction System
SILs	Significant impact levels
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council
SO_2	Sulfur dioxide
TELs	Threshold effects exposure limits
tpy	Tons per year
Updated Project	Reference to EFSB 91-101A
VOCs	Volatile organic compounds
Westinghouse PG	Westinghouse Power Generation
Westinghouse OSC	Westinghouse Services Company
Westinghouse 501G	Model of Gas Turbine being proposed for the project

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions the petition of Cabot Power Corporation to construct a 350 megawatt bulk generating facility and ancillary facilities in Everett, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

On August 15, 1997, Cabot Power Corporation[1] ("CPC" or "Company") filed with the Energy Facilities Siting Board ("Siting Board") an Updated Petition ("updated petition") for approval to construct, own, and operate a 350 megawatt ("MW") gas-fired, combined-cycle cogeneration power plant ("updated project") in the Island End Industrial Park ("IEIP") in Everett, Massachusetts (Exh. CPC-1, at 1). The updated petition follows from CPC's previous March 13, 1991 Petition ("original petition") for approval to construct, own, and operate a 235 MW power plant ("original project") at the same location. The original project was proposed for an in-service date of 1996. After conducting evidentiary hearings, the Siting Board conditionally approved the original project in its Final Decision dated March 9, 1994. Cabot Power Decision, 2 DOMSB at 241 ("1994 Cabot Decision").

The major components of the updated project consist of: (1) a 230 MW Westinghouse 501G combustion turbine-generator with dry low-NO_x combusters; (2) a heat recovery steam generator ("HRSG"); (3) a 120 MW steam turbine-generator; (4) a selective catalytic reduction system; (5) an air-cooled condenser; (6) a turbine air inlet chiller; (7) a CO catalyst system; and (8) a 150-foot exhaust stack (Exh. CPC-1, at 3-6). Other components include a 345 kilovolt ("kV") air-insulated substation and an aqueous ammonia storage tank (id.). Relatively low temperature exhaust steam would be converted to hot water and piped to the adjacent

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1 Cabot Power Corporation ("CPC") was originally incorporated in 1990 to develop, own and operate the project that is the subject of this proceeding. CPC, Distrigas of Massachusetts Corporation ("DOMAC") and MassGas, Inc. are each wholly-owned subsidiaries of Cabot LNG Corporation. Cabot LNG Corporation is in turn a wholly-owned subsidiary of Cabot Corporation, which has been in the energy business since 1882.

DOMAC liquefied natural gas ("LNG") terminal where it was to be used to vaporize LNG (id.).

The primary fuel for the updated project would be vaporized LNG provided by CPC's affiliate, DOMAC, which operates an LNG import terminal adjacent to the site of the updated project (id. at 69). Electrical output would be transmitted to Boston Edison Company's ("BECo") Mystic Station substation by way of an approximately one-half mile, underground 345 kV transmission line (id. at 3, 64-65). CPC anticipates that the updated project would begin commercial operation in mid-2001 (Exh. HO-V-1).

CPC indicated that the updated project would differ from the original project in the following ways: (1) the use of a Westinghouse 501G gas turbine rather than the Westinghouse 501F or General Electric 7111FA turbine proposed for the original project; (2) the use of a "split-shaft" rather than a "single-shaft" design; (3) the elimination of distillate fuel oil as a back-up fuel, which eliminates the need for an oil pipeline between the power plant and the nearby Exxon oil terminal, reduces water consumption for NOx control, and reduces most air emissions; (4) the addition of a CO oxidation catalyst which would reduce the allowable CO emissions of the updated project from 37 to 4.4 parts per million ("ppm"); (5) the substitution of an air insulated for a gas insulated 345 kV substation; and (6) a reduction in the exhaust stack height from 240 feet to 150 feet (Exh. CPC-1, at 4-6). CPC asserts that these changes would allow it to increase the power generating capacity of the updated project by roughly 50 percent while maintaining CO emissions below the level of 98.4 tons per year permitted in the original project.

B. Jurisdiction

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

As a wholesale electric generator with a design capacity of approximately 350 MW, the Company'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, the Company's proposal to construct an electric interconnection, a gas interconnection and other structures at the site falls within the third definition of "facility" set forth in G.L. c. 164, § 69G, which states that a facility is:

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

C. Procedural History

On August 15, 1997, CPC filed with the Siting Board[2] a Motion for Leave to Reopen the Administrative Record ("Motion to Reopen") and an Updated Petition for Approval to Construct a Bulk Generating Facility and Ancillary Facilities ("updated petition") to construct, own, and operate a 350 MW natural gas-fired, combined-cycle cogeneration power plant and ancillary facilities in the Island End Industrial Park in Everett, Massachusetts. On October 31, 1997, CPC filed a Motion for Extension of Time ("Motion for Extension") requesting additional time to meet certain conditions required by the Siting Board in the 1994 Cabot Decision before CPC could receive Final Approval for the original project, namely, the

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2 Prior to September 1, 1992, the Siting Board's functions were effected by the Energy Facilities Siting Council ("Siting Council"). See Acts of 1992, Chapter 141. As the Siting Council was the predecessor agency to the Siting Board, the term Siting Board should be read in this Decision, where appropriate, as synonymous with the term Siting Council.

submittal by March 9, 1998 of signed and approved power purchase agreements which were to include capacity payments for at least 75 percent of the original project's electrical output. See 1994 Cabot Decision, 2 DOMSB at 429. On December 23, 1997, the Siting Board granted both the Motion to Reopen and the Motion for Extension. The Siting Board docketed the updated petition as EFSB 91-101A.

On January 29, 1998, the Siting Board conducted a public hearing in Everett, Massachusetts. In accordance with the direction of the Hearing Officer, the Company provided notice of the public hearing and adjudication.

Late-filed petitions to intervene were filed with the Siting Board on April 6, 1998 by Daniels Printing Limited Partnership ("Daniels") and the Building and Construction Trades Council ("Trades Council"). A letter dated February 2, 1998 was also filed with the Siting Board by Infrastructure Development Corporation ("IDC") seeking to participate as an interested person. CPC filed no opposition to the petitions of Daniels, the Trades Council or IDC.

The Hearing Officer allowed Daniels' status as a full intervenor and denied the petition to intervene by the Trades Council as well as the petition to participate as an interested person of IDC (Hearing Officer Procedural Order, April 15, 1998). The Trades Council filed a Motion to Reconsider Denial of Petition to Intervene with the Siting Board on April 27, 1998 which was denied by the Hearing Officer (Hearing Officer Procedural Order, May 15, 1998). The Siting Board conducted four days of evidentiary hearings commencing on May 27, 1998 and ending on June 22, 1998. CPC presented the testimony of eight witnesses: Daniel Peaco, Manager and Director of LaCapra Associates, testified as to Massachusetts need; Ted Gehrig, Vice President and General Manager for CPC on the updated project, testified as to regional and Massachusetts need, project details, and viability as well as pile driving and safety issues; Peter J. Thalmann, an engineer with PLM Electric Power Engineering, testified as to the regional power system and interconnection with Boston Edison Company; Keith Kennedy and Peter H. Guldberg, Vice President and President, respectively of Tech Environmental, Inc., and Douglas S. Jones, CPC Manager of Environmental Services, testified as to environmental impacts[3]; and George C. Klimkiewicz, Manager of Seismological Services at Weston Geophysical Corporation, and David Myers, Senior Engineer with Environmental Resources Management, both of whom testified as to vibration issues.

Intervenor Daniels presented the testimony of two witnesses: Richard M. Kenney, Chief Administrative and Financial Officer for Daniels, and Andrew Flanders McKown, Vice President of Haley & Aldrich, testified as to vibration issues.

The Hearing Officer entered 261 exhibits into the record consisting primarily of information and record request responses. CPC entered 30 exhibits into the record and Daniels entered 45 exhibits into the record. On July 9, 1998, initial briefs were filed by the CPC and Daniels. On July 21, 1998, reply briefs were filed by CPC and Daniels.

D. Scope of Review

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct facilities, the Siting Board requires applicants to justify generating facility proposals in five phases. First, the Siting Board requires the applicant to show that additional energy resources are needed. ANP Bellingham Energy Company, EFSB 97-1, at 6 (1998) ("ANP Bellingham Decision"); U.S. Generating Company, EFSB 96-4, at 6 (1997) ("Millennium Power Decision"); Northeast Energy Associates, 16 DOMSC 335, 343 (1987) ("NEA Decision"). Second, the Siting Board requires the applicant to show that, on balance, its proposed project is superior to alternative approaches in the ability to address the previously identified need and in terms of cost, environmental impact, and reliability. ANP Bellingham Decision, EFSB 97-1, at 6 (1998); Millennium Power Decision, EFSB 96-4, at 6 (1997); NEA Decision, 16 DOMSC at 364. Third, the Siting Board requires the applicant to show that its project is viable. ANP Bellingham Decision, EFSB 97-1, at 6 (1998); Millennium Power Decision, EFSB 96-4, at 6 (1997); NEA Decision, 16 DOMSC at 364. Fourth, the Siting

[3] Environmental impacts included air quality, noise, water use and waste water discharge, land use, wetlands and waterways, visual, electric and magnetic fields, safety and traffic.

Board requires the applicant to show that its site selection process did not overlook or eliminate clearly superior sites, and in cases where an alternative site has been noticed, that the proposed site for the facility is superior to the alternative site in terms of cost, environmental impact, and reliability of supply. ANP Bellingham Decision, EFSB 97-1, at 6 (1998); Millennium Power Decision, EFSB 96-4, at 6 (1997); NEA Decision, 16 DOMSC at 343. Finally, the Siting Board requires that a proposed project minimize environmental impacts and achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability of supply at the site which is approved. Millennium Power Decision, EFSB 96-4, at 6 (1997); Berkshire Power Decision, 4 DOMSB at 243; Boston Edison Company, 1 DOMSB 1, 149-153, 186-195 (1993) ("1993 BECo Decision").

On December 23, 1997, the Siting Board determined that matters that were addressed in the 1994 Cabot Decision and which are unchanged in the updated petition are not at issue in this case (Procedural Order at 2-3, December 23, 1997). These issues include the superiority of the proposed project to alternative approaches and the site selection process. Consequently, in this decision, the Siting Board's scope of review is limited to: (1) whether additional energy resources are needed (see Section II.A, below); (2) whether the updated project is viable (see Section II.B, below); and (3) whether the updated project minimizes environmental impacts and costs and achieves an appropriate balance among conflicting environmental concerns as well as among environmental impacts, cost and reliability at the proposed site (see Section III.B, below). In reviewing these issues, the Siting Board relies, where the record is unchanged, on the findings made in the 1994 Cabot Decision.

II. ANALYSIS OF THE UPDATED PROJECT

A. Need Analysis

1. Standard of Review

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

In City of New Bedford v. Energy Facilities Siting Council, 413 Mass. 482 (1992) ("City of New Bedford"), the Supreme Judicial Court ("Court") concluded that the Siting Board's finding that New England needed additional energy resources for reliability purposes was inadequate in light of the statutory mandate that an energy supply must be necessary for the Commonwealth. 413 Mass. at 489. In addition, the Court noted that, although the Siting Board had argued that its mandate was to ensure an adequate energy supply at minimum cost, "[e]nsuring an adequate supply is not the same as 'provid[ing] a necessary energy supply for the commonwealth (emphasis added)." City of New Bedford, 413 Mass. at 490, citing G.L. c. 164, § 69H.

In response to the Court's directive in City of New Bedford, the Siting Board set forth a standard of review for the analysis of need for non-utility developers consistent with its statutory mandate -- to implement the Commonwealth's energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost -- in Eastern Energy Corporation (on Remand), 1 DOMSB at 421-423 (1993) ("EEC (remand) Decision").

With respect to the issue of regional need versus Massachusetts need, the Siting Board noted the integration of the Massachusetts electricity system with the regional electricity system and the resulting link between Massachusetts and regional reliability (Id. at 422). The Siting Board noted the inherent reliability and economic benefits which flow to Massachusetts as a result of this integration (Id.). Thus, the Siting Board concluded that consideration of regional need must be a central part of any need analysis for a power generation project not linked to individual utilities by power purchase agreements ("PPAs") (Id. at 416). The Siting Board also noted that the Massachusetts Legislature clearly foresaw the need for "cooperation and joint participation in developing and implementing a regional bulk power supply of electricity" when it enacted G.L. c. 164A and in this same enactment acknowledged that power generating facilities would provide electric power across state lines. G.L. c. 164A, §§ 3, 4. Accordingly, the Siting Board found that an analysis of regional need must serve as a foundation for an analysis of Massachusetts need. EEC (remand) Decision, 1 DOMSB at 417.

In evaluating the need for new energy resources to meet reliability objectives, the Siting Board may evaluate the reliability of supply systems in the event of changes in demand or supply, or in the event of certain contingencies. With respect to changes in demand or supply, the Siting Board has found that new capacity is needed where projected future capacity available to a system is found to be inadequate to satisfy projected load and reserve requirements. ANP Bellingham Decision, EFSB 97-1, at 9; Millennium Power Decision, EFSB 96-4, at 9; New England Electric System, 2 DOMSC 1, 9 (1977). With regard to contingencies, the Siting Board has found that new capacity is needed in order to ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. ANP Bellingham Decision, EFSB 97-1, at 9; Millennium Power Decision, EFSB 96-4, at 9; Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977). The Siting Board also may determine under specific circumstances that additional energy resources are needed primarily for economic or environmental purposes related to the Commonwealth's energy supply. ANP Bellingham Decision, EFSB 97-1, at 9; Millennium Power Decision, EFSB 96-4, at 9; EEC (remand) Decision, 1 DOMSB at 422. With respect to the issue of establishing need on economic efficiency or environmental grounds, the Siting Board notes that such analyses of need would be consistent with its statutory obligation to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H, 69J. ANP Bellingham Decision, EFSB 97-1, at 9; Millennium Power Decision, EFSB 96-4, at 10; Enron Power Enterprise Corporation, 23 DOMSC 1, 49-62 (1991) ("Enron Decision").

Further, while acknowledging that G.L. c. 164, § 69H requires the Siting Board to ensure a necessary supply of energy for Massachusetts, the Siting Board interprets this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources,[4] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. ANP Bellingham Decision, EFSB 97-1, at 10; Millennium Power Decision, EFSB 96-4, at 10; Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985) ("1985 MECo/NEPCo Decision"). In doing so, the Siting Board fulfills the requirements of G.L. c. 164, § 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region and that reliability and economic benefits flow to Massachusetts from Massachusetts utilities' participation in the New England Power Pool ("NEPOOL").

The Siting Board has found that a demonstration of Massachusetts need based on reliability, economic efficiency or other benefits associated with additional energy resources from a proposed project remains a necessary element of a need review. ANP Bellingham Decision, EFSB 97-1, at 10; Millennium Power Decision, EFSB 96-4, at 10; EEC (remand) Decision, 1 DOMSB at 417-418. However, in response to the Court's reminder in City of New Bedford that its statutory mandate is limited to ensuring that a necessary energy supply is provided for the Commonwealth, the Siting Board found in the EEC (remand) Decision that reliability, economic, or environmental benefits associated with the additional energy resources from a proposed project must directly relate to the energy supply of the Commonwealth for

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

them to be considered in support of a finding of Massachusetts need. 1 DOMSB at 418. See also Cabot Decision, 2 DOMSB at 258; Altresco Lynn Decision, 2 DOMSB at 26.

In its first review of a petition by a non-utility generator ("NUG") to construct a jurisdictional facility, the Siting Board found that, consistent with current energy policies of the Commonwealth, Massachusetts benefits economically from the addition of cost-effective qualifying facility ("QF")[5] resources to its utilities' supply mix. NEA Decision, 16 DOMSC at 358. In that case, the Siting Board also found (1) that a signed and approved PPA between a QF and a utility constitutes prima facie evidence of the utility's need for additional energy resources for economic efficiency purposes, and (2) that a signed and approved PPA which includes a capacity payment constitutes prima facie evidence for the need for additional energy resources for reliability purposes (id.). Thus, in cases where a non-utility developer sought to construct a jurisdictional generating facility principally for a specific utility purchaser or purchasers, the Siting Board has required the applicant to demonstrate that the utility or utilities need the facility to address reliability concerns or economic efficiency goals through presentation of signed and approved PPAs. MASSPOWER, Inc., 21 DOMSC 196, 200 (1990); MASSPOWER, Inc., 20 DOMSC 1, 19-23, 32 (1990) ("MASSPOWER Decision"); Altresco-Pittsfield Decision, 17 DOMSC at 366-367. Two 1995 decisions of the Court, however, bring into question further reliance on such prima facie evidence in this and future cases.[6]

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5 The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 796, 824a-3 ("PURPA"), established a QF category consisting of non-utility electric cogenerators with the capability to generate both electric energy and useable steam. In order to qualify for QF status under PURPA, the cogenerator had to certify to the Federal Energy Regulatory Commission ("FERC") that it would sell a specified portion of its steam by-product in addition to its electric sales.

6 In Point of Pines Beach Association v. Energy Facilities Siting Board, the Court noted the Siting Board's statutory requirement to make an independent finding of Commonwealth need, a finding that could not be premised solely on the existence of signed and approved PPAs. 419 Mass. 281, 285-286 (1995) ("Point of Pines").
(continued...)

Where a non-utility developer has proposed a generating facility for a number of power purchasers that include purchasers that are as yet unknown, or for purchasers with retail service territories outside of Massachusetts, the need for additional energy resources must be established through an analysis of regional capacity and a showing of Massachusetts need based on reliability, economic or environmental grounds directly related to the energy supply of the Commonwealth. ANP Bellingham Decision, EFSB 97-1, at 11-12; Millennium Power Decision, EFSB 96-4, at 12; West Lynn Cogeneration, 22 DOMSC 1, 9-47 (1991) ("West Lynn Decision"). Consistent with the Siting Board's precedent and reflecting the directives of the Court in City of New Bedford, Point of Pines, and Attorney General, the Siting Board here reviews CPC's analysis of the need for the updated project for reliability purposes.[7]

2. Reliability Need

The Siting Board has found that it is appropriate to consider the need for capacity beyond the first year of proposed facility operation as part of assessing need for reliability purposes in reviews of NUG projects. See ANP Bellingham Decision, EFSB 97-1, at 12; Millennium Power Decision, EFSB 96-4, at 12; West Lynn Decision, 22 DOMSC at 14, 33-34. The Siting Board has acknowledged that the longer time frame is potentially useful

(...continued)

Referencing its decision in Point of Pines, the Court vacated a final decision of the Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) ("Attorney General").

7 In the 1994 Cabot Decision, the Siting Board considered the need for the original project for both reliability and economic efficiency purposes. 2 DOMSB at 300. In this proceeding, the Company presented a comparison of the projected cost of power from the updated project with the Standard Offer Distribution Company Rates in the NEES Settlement Agreement for the years 2000 through 2004 (Exh. CPC-1, at 51). While the comparison provides evidence of the likely competitiveness of the updated project, it does not represent an updated economic dispatch analysis of the type needed to support findings of need based on economic efficiency. Consequently, the Siting Board does not evaluate the need for additional energy resources from the updated project for economic efficiency purposes in this decision.

regardless of whether need has been established for the first year of proposed operation. If need has been established for the first year, the longer time frame helps ensure that the need will continue over a number of years, and is not a temporary aberration. If need has not been established for the first year of proposed operation, a demonstration of need within a limited number of years thereafter may still be an important factor in reaching a decision as to whether a proposed project should go forward. Thus for the purposes of this review, the Siting Board finds that it is appropriate to consider explicitly need for the updated facility during the 2001 to 2006 time period.

a. New England

CPC asserted that there is a need for at least 330 MW[8] of additional energy resources in New England beginning in the year 2001 and beyond (Exh. CPC-1, at 18; Tr. 1 at 33; CPC Brief at 16). In support, the Company presented a series of forecasts of demand and supply for the region based primarily on the 1998 Capacity, Energy Loads, and Transmission ("CELT") forecasts and other data published by NEPOOL (Exhs. HO-N-15; HO-N-15(S)).[9] The Company indicated that it combined its demand and supply forecasts to produce a series of need forecasts (Exh. CPC-1, at 31-32).

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[8] The Company indicated that the updated project's summer capacity rating is 330 MW, its winter peak productive capacity is 395 MW, and its nominal average rating is 350 MW (Exh. CPC-1, at 18; Tr. 1, at 33). The Company stated that it assessed the need for 330 MW, the summer peak load, because the reliability need is more acute in the summer season rather than the winter season ((Exh. CPC-1, at 18; Tr. 1, at 32). In Section II.A.2.a.iii below, the Siting Board evaluates the need for 350 MW, the average annual capacity rating of the updated project. Use of the average annual rating is conservative in the case of a summer need analysis.

[9] The Company initially relied on the 1997 CELT forecasts (Exhs. CPC-1, at 28, Appendix E, Appendix F; HO-N-15). During the course of the proceedings, NEPOOL issued the 1998 CELT report. CPC indicated that the 1998 CELT report projects a higher summer peak load than the 1997 CELT report (see Exh. HO-N-2(S)). For purposes of this analysis, the Siting Board will focus on the 1998 CELT report.

The Company stated that the forecasts of summer demand and supply were developed from individual forecasts of several underlying factors including: (1) unadjusted peak loads; (2) utility-sponsored demand side management ("DSM") resources available on peak; (3) NUG netted from load; (4) supply resources; and (5) required reserve margin (id. at 20; Tr. 1, at 36). The Company stated that it developed an adjusted summer peak load forecast by subtracting the DSM and NUG factors from the unadjusted peak load (Tr. 1, at 36).

In the following sections, the Siting Board reviews the Company's demand forecasts, including its demand forecast methods and estimates of DSM savings over the forecast period, and the Company's supply forecasts, including its capacity assumptions and required reserve margin assumptions. The Siting Board then analyzes a series of need forecasts.

(1) Demand Forecasts

(a) Description

CPC presented forecasts of unadjusted summer peak load and DSM savings derived from information contained in the 1998 CELT report (Exhs. HO-N-15(S); HO-RR-1).

To develop forecasts of adjusted load, the Company combined each of these peak load forecasts with (1) the 1998 CELT report forecast of NUG netted from load, and (2) one of three forecasts of DSM savings based on the 1998 CELT report forecast of DSM savings (Exhs. HO-N-15(S); HO-RR-1).

(i) Demand Forecast Methods

The Company presented a base case unadjusted peak load forecast, derived directly from the 1998 NEPOOL CELT report reference forecasts of unadjusted load for summer peak ("1998 CELT forecast") (Exh. HO-N15(S)). The Company stated that NEPOOL uses a sophisticated end-use model based on a number of New England economic variables to forecast trends in the economy and resulting levels of energy consumption and peak demand (Tr. 1, at 37). The Company asserted that the reference forecast provides a reasonable projection of regional demand (Exh. CPC-1, at 31).[10] The Company indicated that the 1998 CELT report does not contain high and low load forecast scenarios (Exh. N-15(S)). Therefore, the Company also presented the 1997 CELT report high case ("CELT high case") and low case ("CELT low case") demand forecasts, which are based on optimistic and pessimistic economic forecasts, respectively, to illustrate the full range of uncertainty in the peak load (Exhs. CPC-1, 30, 32, App. F).[11]

(ii) DSM

The Company provided three forecasts of DSM: (1) a base DSM scenario, which is the current forecast of company-sponsored DSM savings used in NEPOOL's 1998 CELT report;[12] (2) a high DSM scenario, which is 110 percent of the base DSM scenario; and (3) a low DSM scenario, which is 90 percent of the base DSM scenario (Exhs. CPC-1, at 32: HO-N-3(S)). The Company stated that, historically, NEPOOL has overestimated DSM savings but that more recent NEPOOL forecasts have been lower and closer to actual savings (Exh. CPC-1, at 32).

10 The Company indicated that the 1997 CELT forecast was derived by updating the 1996 CELT forecast in the short-term (1997 to 2000) only (Exh. HO-N-2). The Company indicated that NEPOOL has prepared a new short-run and long-run load forecast for the 1998 CELT report (Exh. HO-N-2(S)). The Company explained that the 1998 load forecast is higher than the 1997 forecast as the new forecast includes updated historical, economic and demographic inputs that reflect the expected price decrease resulting from the deregulation of the electric industry (id.).

11 CPC stated that NEPOOL estimates the CELT low case demand forecast to have a 90 percent chance of being exceeded and the CELT high case demand forecast to have a ten percent chance of being exceeded (Exh. CPC-1, at 32).

12 The Company indicated that NEPOOL has prepared a new forecast of DSM for the 1998 CELT report (Exh. HO-N-2(S)). The Company stated that the update results in a lower level of peak load and energy impacts relative to the 1997 forecast after 2002 in the summer and in all years in the winter (id.).

(iii) Adjusted Load Forecasts

The Company stated that to develop forecasts of adjusted load, the 1998 CELT unadjusted summer base case load forecast was combined with the (1) the 1998 CELT report forecast of NUG netted from load, and (2) three forecasts of DSM savings (Exh. HO-N-3(S)). Thus, the Company presented three forecasts of adjusted summer peak load based on the 1998 CELT forecast report.

(b) Analysis

The Siting Board previously has acknowledged that the CELT report generally can provide an appropriate starting point for resource planning in New England, and has accepted the use of CELT forecasts for the purposes of evaluating regional need in previous reviews of proposed NUG facilities. ANP Bellingham Decision, EFSB 97-1, at 16; Millennium Power Decision, EFSB 96-4, at 16; NEA Decision, 16 DOMSC at 354. In addition, the Siting Board has relied primarily on the more recent available forecasts in its analysis of need. See Berkshire Power Decision, 4 DOMSB at 257.

Here, the Company derived an unadjusted base case summer demand forecast and base case DSM scenario directly from the 1998 CELT forecast, which is the most recent CELT forecast. The Company derived two additional DSM scenarios from the base DSM scenario. The Company adjusted the unadjusted base case forecast by base, high and low DSM scenarios, for a total of three adjusted forecasts.

In addition, the Company provided the 1997 CELT high case demand forecast and CELT low case demand forecast as extreme demand forecasts, in order to test the sensitivity of the results of analysis of the base case forecast.[13] As noted above, NEPOOL assigns a low probability of occurrence to each of these forecasts. Consistent with previous Siting Board decisions (see, e.g., ANP Bellingham Decision, EFSB 97-1, at 16; Millennium Power

[13] As indicated above, the 1998 CELT report does not contain high and low load forecast scenarios, therefore for these purposes, the Siting Board relies on the 1997 CELT high and low load forecast scenarios.

Decision, EFSB 96-4, at 17; 1994 Cabot Decision, 2 DOMSC at 274), the Siting Board finds that these forecasts represent a sensitivity analysis of varying economic assumptions rather than forecasts of regional demand.

Overall, the Company has presented one base case forecast adjusted by three forecasts of DSM. Given uncertainties in forecasting demand, the Siting Board has previously found that it is reasonable to include a range of forecasts in a company's reliability need analysis. See, e.g., ANP Bellingham Decision, EFSB 97-1, at 16-17; Millennium Power Decision, EFSB 96-4, at 17; Berkshire Power Decision, 4 DOMSB at 261, n.23. However, as noted above, the Siting Board has acknowledged the value of the CELT report for regional resource planning and has accepted the use of CELT forecasts for the purpose of evaluating regional need. In addition, in reviewing need forecasts, the Siting Board has placed more weight on the base case forecast. Berkshire Power Decision, 4 DOMSB at 274. Here, the Company has provided the most recent CELT forecast as a base case forecast and also has provided high and low forecasts from a recent CELT forecast for the purpose of demonstrating the range of potential demand. Therefore, the Siting Board finds that it is reasonable, for purposes of this review, to rely on one base case forecast for summer peak load.

Accordingly, the Siting Board finds that the 1998 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2001 and beyond.

The Company also provided three forecasts of utility-sponsored DSM -- a base case scenario, which is NEPOOL's current forecast of company-sponsored DSM savings, a low DSM scenario which discounts NEPOOL's projected DSM growth rates by ten percent, and a high DSM forecast, which inflates NEPOOL's projected DSM growth rates by ten percent. As noted above, although NEPOOL historically has overestimated DSM savings, the more recent NEPOOL forecasts of DSM have been lower and closer to actual savings. The Company's symmetrical ten percent adjustment of NEPOOL's DSM forecast is consistent with the trend toward the successive lowering of NEPOOL's DSM forecasts, and is consistent with the DSM scenarios accepted by the Board in its most recent generating facility decisions. See ANP Bellingham Decision, EFSB 97-1, at 17; Millennium Power Decision, EFSB 96-4, at 17-18.

Accordingly, for purposes of this review, the Siting Board finds that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In sum, the Siting Board has accepted one forecast of summer peak load. In addition, the Siting Board has accepted three forecasts of DSM -- a base case, low case and high case. Therefore, the Siting Board here accepts three forecasts of adjusted summer peak load for the purposes of this review.

(2) Supply Forecasts

(a) Description

(i) Capacity Assumptions

CPC presented three supply scenarios -- base, high and low -- based in large part on the supply resources included in the 1998 CELT report (Exhs. CPC-1, at 33; HO-N-8; HO-N-8(S)). The Company stated that it updated the 1998 NEPOOL supply forecast to reflect changes in the regional supply not included by NEPOOL (Exhs. HO-N-8; HO-N-8(S); HO-N-2(S)).[14] Specifically, beginning in 2001, the Company deducted the capacity of:

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[14] The Company noted that the difference between the adjusted base case supply for the 1997 CELT and the 1998 CELT is an increase of approximately 200 MW (Tr. 1, at 51). CPC listed the most notable changes from the 1997 CELT: (1) the removal of capacity from Maine Yankee; (2) the deferral of the restart of Millstone 1 and 2; (3) the addition of new capacity from Bridgeport Harbor Combined Cycle in Connecticut, Berkshire Power in Massachusetts, Dighton Power in Massachusetts, Androscoggin Energy in Maine, and Worcester Energy in Maine; and (4) the reactivation of Indeck Jonesboro, West Enfield, and Mason Station, all located in Maine (Exhs. HO-N-2(S);
(continued...)

(1) the Middletown 1 unit (66 MW), and the Norwalk Harbor 10 unit (12 MW), both reactivated from deactivated reserve in 1996 as a temporary response to the Millstone unit outages; and (2) the Mason 3,4,5 Units (92 MW) (Exhs. HO-N-8(S); HO-N-8). CPC also added the capacity of: (1) the Wyman 1-3 units (223 MW); and (2) the Devon 11-14 units (125 MW), both of which consist of combustion turbines recently granted permanent operating permits (Exh. HO-N-8(S)).

The Company stated that, to reflect uncertainties in future capacity in its supply scenarios, it then adjusted the 1998 NEPOOL forecast by varying projections of: (1) the availability of existing fossil fuel-steam units; (2) the availability of existing nuclear units; and (3) the capacity of new projects currently being developed (Exhs. CPC-1, at 33-41; HO-N-8; HO-N-8(S)). CPC asserted that the CELT supply forecast overstates expected future capacity from existing nuclear units and fossil fuel steam units because it is simply a tabulation of all existing generating units based on their design or contract life without consideration of uncertainty in future availability (Exh. CPC-1, at 33). Specifically, the Company stated that the 1998 CELT report assumes: (1) the continued operation of all active nuclear units in the region for the full terms of their current operating licenses, even though these units are old and are facing significant regulatory, technical and economic issues; and (2) the limited retirement of existing fossil fuel steam units that have been in operation for more than 25 years even though 1,500 MW will be at least 40 years old by 2000 and 3,200 MW will be at least 40 years old by 2005 (id. at 34, 39).

With respect to nuclear units, CPC stated that the Millstone 1 unit (641 MW) has been out of service since 1995 and that the Millstone 2 and 3 units (2030 MW) have been out of service since 1996 (id. at 35-36). CPC stated that Northeast Utilities ("NU") has indicated its expectation that the Nuclear Regulatory Commission will approve the re-start of the Millstone 2 and 3 units by mid-1998 and has also indicated that it will examine whether to restart the Millstone 1 unit later in 1998 (Exh. HO-N-9; Tr. 1, at 48-49). CPC argued that it is

[14](...continued)
HO-N-1 (Att. 2)).

increasingly likely that the Millstone 1 unit will be retired (Exh. HO-N-9; Tr. 1, at 48-49). CPC noted that the Connecticut Department of Public Utility and Control recently issued an order finding the Millstone 1 unit not used and useful based on NU's deferral of maintenance on this unit in favor of the Millstone 2 and 3 units, and thus removed the Millstone 1 unit from rate base (Exh. HO-N-9 (Att.1)).

The Company stated that the older fossil fuel steam units will typically require increased expenditures for operations and maintenance ("O&M") and potential capital costs to comply with Phase II of the Clean Air Act Amendments of 1990 ("CAAA") (Exh. CPC-1, at 39).[15] The Company explained that many of these expenditures likely will be difficult to justify under restructuring due to competition from new generation technology which has significant efficiency, economic and environmental advantages (id.). CPC also noted that these units may experience performance degradation due to their age (id.).

In addition, the Company stated the 1998 CELT supply forecast does not include the capacity from all proposed new generating facilities that have reached significant licensing completion (Exh. HO-N-7).[16] The Company noted, however, the 1998 CELT report did include four new generating facilities that were not included in the 1997 CELT report -- Berkshire Power Development (265 MW), Dighton (170 MW), Bridgeport Harbor, Connecticut (520 MW), and Androscoggin, Maine (142 MW) (Exhs. HO-N-2(S); HO-N-8(S)). The Company also indicated that two new proposed generating facilities have reached significant licensing milestones -- Tiverton, Rhode Island (250 MW), and Millennium (360

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15 CPC indicated that Phase II of the CAAA will require additional nitrogen oxides ("NOx") reductions to be implemented by 2000 (Exh. CPC-1, at 39).

16 The Company indicated that the 1998 CELT supply forecast includes the capacity of the following categories of projects under development: (1) construction complete, not yet in operation; (2) under construction, has complete regulatory approval; (3) under licensing consideration; and (4) proposed (Exh. HO-N-7).

MW) (Exhs. HO-N-7; HO-N-8).[17]

For its base supply scenario, the Company assumed reductions in the 1998 CELT forecast capacity based on retirement of (1) the Millstone 1 unit (641 MW), and (2) 25 percent of the fossil-fired steam capacity that is at least 40 years old (492 MW in 2001 increasing to 908 MW in 2006)[18] (Exhs. CPC-1, at 40; HO-N-8(S)). In addition, the Company added 50 percent of the capacity of new generating units that have reached significant licensing completion (305 MW) (Exhs. HO-N-8(S); HO-N-8).

For the high supply scenario, the Company assumed that: (1) the Millstone 1 unit would be returned to service (641 MW); (2) ten percent of the fossil-fired steam capacity that is at least 40 years old would be retired (197 MW in 2001); and (3) 80 percent of the capacity of new generating units that have reached significant licensing completion would come on-line as scheduled (488 MW) (Exhs. CPC-1, at 40; HO-N-7; HO-N-8; HO-N-8(S)). For the low supply scenario, the Company assumed that (1) the Millstone 1 and 2 units would be retired (1,512 MW); (2) 50 percent of the fossil-fired steam capacity that is at least 40 years old would be retired (984 MW in 2001); and (3) 20 percent of the capacity of new generating units that have reached significant licensing completion would come on-line as scheduled (122 MW) (Exhs. CPC-1, at 40; HO-N-7; HO-N-8; HO-N-8-(S)).

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17 The Company indicated that there are a number of other new generating units proposed in the region that are not included in its supply forecast because of the degree of uncertainty associated with the projects (Tr. 1, at 45). The Company argued that it would be both difficult and inconsistent with past Siting Board practice to give significant weight to projects that are not as far along in the development process as CPC (id.).

18 The Company stated that these assumptions are similar to those adopted by the Siting Board in previous cases, except that no specific unit has been used as a proxy for these retirements in any of the cases (Exh. CPC-1, at 40, n. 17) (citing Berkshire Power Decision, 4 DOMSB at 270). CPC noted that in the Berkshire Power Decision, the Salem Harbor 1-3 units were used as a proxy for such retirements in the base case (id.).

ii) Reserve Margin

The Company indicated that it adopted NEPOOL's most current projections of required reserve margins which are set forth in the September 1994 NEPOOL document, "1994 Annual Review of NEPOOL Objective Capability and Associated Parameters" (Exh. CPC-1, at 33). CPC stated that, in that document, NEPOOL specifies required reserve margins of 15 percent of adjusted peak load (id.).[19]

(b) Analysis

The Company has presented a base supply scenario which was based on the 1998 CELT report supply forecast, updated to reflect adjustments for actual, planned and likely changes to NEPOOL supply. In addition, to account for uncertainties in future availability, the Company then adjusted the updated 1998 NEPOOL forecast by varying projections of three categories of capacity to develop base, high and low supply scenarios. Here, the Siting Board considers the reasonableness of the Company's assumptions.

The Company's adjustments to the 1998 CELT report supply forecast included changes to reflect likely long-term status of units put in service as a temporary response to the Millstone outages. The Company deleted the capacity of older units that were reactivated from deactivated reserve and added the capacity of units put into service that have received permanent operating permits. For purposes of this review, the Siting Board accepts the Company's assumptions.

As noted above, in the base case supply scenario, the Company assumed that 25 percent of the capacity of fossil fuel steam units that have been in operation for more than 40 years would be retired -- 492 MW in 2001 increasing to 908 MW in 2006. The Siting Board notes that it is reasonable to conclude that a portion of the units operating beyond retirement guidelines will be retired beginning in 2001, especially in light of CAAA requirements that are

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19 CPC noted that the 15 percent reserve margin assumes that the Hydro-Quebec contract is not counted as firm capacity and that if Hydro-Quebec were treated as firm capacity the required reserves would be higher (Exh. CPC-1, at 33, n. 12).

likely to take effect by 2000. In previous reviews the Siting Board has accepted assumptions that one unit operating beyond NEPOOL's guidelines for retirement, or a like amount of capacity, would be retired. See, ANP Bellingham Decision, EFSB 97-1, at 23; Millennium Power Decision, EFSB 96-4, at 24; Berkshire Power Decision, 4 DOMSC at 270. The capacity reduction here for the year 2001 is consistent with previous reviews. Therefore, the Siting Board accepts the Company's assumption regarding retirement of fossil fuel steam units operating for more than 40 years.

The Company also assumed that the Millstone 1 unit would be retired in the base case supply scenario. The record demonstrates that the Millstone 1 unit has been out of service since 1995, that NU has not decided whether to restart the unit, that NU has deferred maintenance on the unit and that the Connecticut Department of Public Utility and Control has removed the unit from rate base. Therefore, for purposes of this review, the Siting Board accepts the Company's assumption of the retirement of the Millstone 1 unit. In addition, the Siting Board recognizes that it is appropriate to account for additional NUG resources that may commence operation during the forecast period. Here, the Company included 50 percent of the capacity of those units that have reached significant licensing completion. The Company's criteria for including new proposed units is reasonable given the development, licensing, financing, and construction uncertainties that could affect the successful completion of units that are not fully licensed and under construction and is consistent with Siting Board precedent. Therefore, for purposes of this review, the Siting Board accepts the Company's assumptions regarding the inclusion of newly proposed units in the base case supply scenario.

Accordingly, the Siting Board finds that the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need. In addition, the Siting Board finds that the assumptions reflected in the Company's low case supply scenario are reasonable low case assumptions and that the low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need. The Siting Board further finds that the assumptions reflected in the Company's high case supply scenario are reasonable high case assumptions and therefore that the high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need.

Finally, with respect to reserve margins, the Company used NEPOOL's projected reserve margin for the year 2001 and reasonably assumed that the reserve margins would remain at the projected values for the year 2001 in the years 2002 through 2006. Accordingly, consistent with recent Siting Board decisions, the Siting Board finds that the reserve margins projected by the Company are appropriate for purposes of this review.

(3) Need Forecasts

(a) Description

The Company developed nine need forecasts by adjusting the 1998 CELT summer peak load forecasts by each of three DSM scenarios, and combining each of the resulting three adjusted demand forecasts with three supply forecasts (Exhs. HO-N-15(S); HO-RR-1). All nine of these need forecasts demonstrate a sustained need for at least 350 MW of capacity in 2001 (id.). See Table 1, below.

Table 1

RANGE OF REGIONAL NEED CASES

2001

Demand Case	DSM	High Supply	Base Supply	Low Supply
1998 CELT	High	(1,552)	(2,672)	(4,217)
1998 CELT	Base	(1,726)	(2,846)	(4,391)
1998 CELT	Low	(1,900)	(3,020)	(4,565)

Source: Exhs. HO-N-15(S); HO-RR-1.
Note: Capacity deficits are shown in ( ).

(b) Analysis

In considering the Company's forecasts of summer and winter peak load, the Siting Board has found that the 1998 CELT forecast is an appropriate base case summer peak load forecast for use in the analysis of regional need for the years 2001 and beyond. In considering the Company's DSM forecasts, the Siting Board has found that: (1) the Company's base DSM scenario represents an appropriate base case forecast of DSM savings for use in the regional need analysis; (2) the Company's low DSM scenario represents an appropriate low case forecast of DSM savings for use in the regional need analysis; and (3) the Company's high DSM scenario represents an appropriate high case forecast of DSM savings for use in the regional need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of regional need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of regional need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of regional need. In addition, the Siting Board has found that the reserve margins projected by the Company are appropriate for the purposes of this review.

The capacity positions under the summer need forecasts based on the 1998 CELT summer peak load forecast for the year 2001 are shown in Table 1, above. All nine need forecasts demonstrate a sustained need for at least 350 MW of capacity in 2001. Accordingly, the Siting Board finds that there is a sustained need for 350 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2001.

b. Massachusetts

The Company asserted that there is a need for new capacity in Massachusetts by the year 2001 (CPC Brief at 35). To support its assertions, the Company presented a series of forecasts of demand and supply for Massachusetts, based primarily on NEPOOL's 1998 CELT forecast prorated to Massachusetts (Exhs. CPC-1, at 46; HO-N-4(S); HO-N-11; HO-N-15(S)).

The Company stated that it then combined its demand and supply forecasts to produce a series of need forecasts (Exh. CPC-1, at 47).

In the following sections, the Siting Board reviews the demand forecasts provided by the Company, including its demand forecast methods and estimates of DSM savings over the forecast period, and the supply forecasts provided by the Company, including its capacity assumptions and required reserve margin assumptions. The Siting Board then reviews the Company's need analyses for Massachusetts.

(1) Demand Forecasts, DSM and Adjusted Load Forecasts

(a) Description

The Company indicated that it relied primarily on information contained in the 1998 CELT report and NEPOOL's most recent Massachusetts-specific forecast of adjusted summer peak load,[20] which was published in 1994, to develop a Massachusetts peak load forecast (id.). The Company explained that it prorated the 1998 CELT unadjusted reference forecast by the ratio of the 1994 NEPOOL forecast for Massachusetts to the 1994 CELT reference forecast to develop a Massachusetts unadjusted reference forecast (id.). The Company indicated that it applied the same 1994 ratios to the 1998 CELT report forecasts of base, high and low DSM and of NUG netted from load, and subtracted these prorated forecasts from the Massachusetts unadjusted reference forecast to develop the Massachusetts adjusted load forecasts (Exh. HO-N-4(S)). In addition, the Company stated that it applied the 1994 ratios to the 1997 CELT high and low load forecasts to develop the Massachusetts high case and low case forecasts, respectively (Exh. CPC-1, at 47).

20 CPC stated that the need for capacity in Massachusetts, like the regional need, is driven by the summer peak load rather than the winter peak load (Exh. CPC-1, at 47).

(b) Analysis

In its Massachusetts need analysis, CPC provided base case demand forecasts for adjusted summer peak load which correspond to the base case demand forecasts presented in its regional need analysis. CPC also provided high and low forecasts of summer peak load demand in Massachusetts which correspond to the high and low forecasts presented in the regional need analysis. Additionally, the Company provided high and low DSM cases for Massachusetts, which correspond to the set of assumptions used in the regional analysis.

The Siting Board reviewed the regional demand forecasts in Section II.A.2.a.i, above. Consistent with its findings concerning the regional demand forecasts, the Siting Board finds that (1) the 1998 Massachusetts forecast of summer peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need, and (2) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand.

With respect to DSM, the Company provided three forecasts of DSM savings corresponding to the forecasts of DSM savings presented in its regional need analysis. The Siting Board reviewed the regional DSM forecasts in Section II.A.2.a.i.(A), above. Consistent with its findings concerning the regional forecasts of DSM savings, the Siting Board finds that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

(2) Supply Forecast and Reserve Margin

(a) Description

CPC stated that it developed base, high and low supply scenarios for Massachusetts, consistent with its regional supply scenarios, with adjustments to reflect the generating resource ownership and commitments of Massachusetts electric utility companies (Exh.CPC-1, at 47).

The Company stated that it used information from the 1998 CELT report to determine, on a utility-by-utility basis, the capacity committed to utilities serving Massachusetts customers, including the total capability for utility generating capacity and non-utility capacity purchases claimed by utilities serving load exclusively within Massachusetts, combined with a percentage of the capability claimed by Massachusetts utilities that are part of holding companies serving load in multiple states including Massachusetts (id. at 47; Exhs. HO-N-8(S); HO-N-11). The Company stated that it allocated an amount of these multi-state holding-companies' capacity to Massachusetts by calculating for each such holding company the ratio of Massachusetts peak load to total peak load on each system, and then using this ratio to apportion to Massachusetts the capacity of each generating facility owned by the holding company (Exh. HO-N-14).[21]

The Company stated that its Massachusetts base, high and low case supply scenarios are comparable to the regional base, high and low case supply scenarios (Exh. CPC-1, at 47). In allocating the share of the projects currently under development to Massachusetts, CPC assumed that Massachusetts consumers would purchase output from these facilities in proportion to Massachusetts' share of the New England market (id.; HO-N-14).

The Company stated that it assumed the same yearly percentage reserve margin requirements for Massachusetts as were assumed for the region (Exh. CPC-1, at 47). These percentages were applied to the Massachusetts load forecasts (id.).

21 The Company stated that the ratios for the Massachusetts share of multi-state utility capacity are: (1) 0.734 for New England Electric System; (2) 0.608 for Eastern Utilities Associates; and (3) 0.113 for NU (Exh. HO-N-14).

(b) Analysis

The Company provided a base case, low case and high case supply scenario for Massachusetts, corresponding to the supply forecasts presented in its regional need analysis. The Siting Board reviewed those forecasts in Section II.A.2.a.ii, above.

Consistent with its findings relative to the regional need analysis, the Siting Board finds that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need.

The Company assumed the same percentage reserve margin requirements for Massachusetts as were assumed for the region. Consistent with its findings relative to the regional need analysis, the Siting Board finds that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

(3) Need Forecasts

(a) Description

Consistent with its regional need forecasts, the Company developed nine summer need forecasts by adjusting the 1998 Massachusetts forecast by each of three DSM scenarios, and combining each of the resulting three summer adjusted demand forecasts with three supply forecasts (Exhs. HO-N-15; HO-RR-1, Att.3, Att.4, Att.5). Of these nine summer need forecasts, all demonstrate a sustained need for at least 350 MW of capacity in 2001. See Table 2, below.

Table 2

RANGE OF MASS NEED CASES

2001

Demand Case	DSM	High Supply	Base Supply	Low Supply
1998 CELT	High	(1,541)	(1,807)	(2,172)
1998 CELT	Base	(1,623)	(1,889)	(2,254)
1998 CELT	Low	(1,706)	(1,972)	(2,336)

Source: Exh. HO-RR-1, Att.3, Att.4, Att.5
Capacity deficits are shown in ( ).

(b) Analysis

Consistent with the regional need analysis, the Siting Board finds that it is appropriate to consider explicitly Massachusetts need for the updated project starting in 2001, the year that the project is proposed to enter service.

The Siting Board has found that (1) the 1998 Massachusetts forecast of summer peak load is an appropriate base case peak load forecast for use in the analysis of Massachusetts need, and (2) the CELT report high case and low case demand forecasts for Massachusetts represent a sensitivity analysis of varying economic assumptions rather than forecasts of Massachusetts demand.

In considering the Company's DSM forecasts, the Siting Board has found that: (1) the base Massachusetts DSM scenario represents an appropriate base case forecast of DSM savings for use in the Massachusetts need analysis; (2) the high Massachusetts DSM scenario represents an appropriate high case forecast of DSM savings for use in the Massachusetts need analysis; and (3) the low Massachusetts DSM scenario represents an appropriate low case forecast of DSM savings for use in the Massachusetts need analysis.

In considering the Company's supply forecasts, the Siting Board has found that: (1) the Company's base supply scenario represents an appropriate base case supply forecast for use in the analysis of Massachusetts need; (2) the Company's low case supply scenario represents an appropriate low case supply forecast for use in the analysis of Massachusetts need; and (3) the Company's high case supply scenario represents an appropriate high case supply forecast for use in the analysis of Massachusetts need. In addition, the Siting Board has found that, for purposes of this review, the reserve margin requirements projected by the Company are appropriate.

The capacity positions under the Massachusetts summer need forecasts, based on the 1998 CELT summer peak load forecast for Massachusetts, for the 2001 are shown in Table 2, above. All such summer need forecasts show a sustained need for at least 350 MW in 2001. Accordingly, the Siting Board finds that there is a sustained need for 350 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2001.

3. Conclusions on Need

The Siting Board has found that there will be a sustained need for 350 MW or more of additional energy resources in New England for reliability purposes beginning in the year 2001. In addition, the Siting Board has found that there will be a sustained need for 350 MW or more of additional energy resources in Massachusetts for reliability purposes beginning in the year 2001.

Based on a showing of a sustained need for 350 MW or more of additional energy resources in the Commonwealth for reliability purposes, the Siting Board finds that the updated project is needed to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, beginning in the year 2001.

In the 1994 Cabot Decision, the Siting Board found need for the original project was based on the submission of signed and approved PPAs which include capacity payments for at least 75 percent of the original project's electric output. 2 DOMSB at 333. In this proceeding, the Siting Board finds that there is a sustained need for 350 MW or more of additional energy resources in the Commonwealth for reliability purposes. Consequently, the Siting Board will no longer require CPC to comply with Condition A of the 1994 Cabot Decision, which required CPC to demonstrate need through the submission of signed and approved PPAs.

B. Project Viability

1. Standard of Review

a. Existing Standard

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. ANP Bellingham Power Decision, EFSB 97-1, at 66; Millennium Power Decision, EFSB 96-4, at 71; Berkshire Power Decision, 4 DOMSB at 346.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. ANP Bellingham Power Decision, EFSB 97-1, at 66; Millennium Power Decision, 96-4, at 72; Berkshire Power Decision, 4 DOMSB at 345.[22]

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[22] The Siting Board issued a Determination on August 17, 1998, regarding its fundamental standard of review for viability in light of ongoing changes in the electricity industry. The Determination states that the Siting Board will not continue to conduct a stand alone review of project viability for generating facilities filed pursuant to G.L. c. 164 §§ 69H and J¼. Because the updated project was filed pursuant to G.L. c. 164 § 69J, rather (continued...)

2. Financiability and Construction

a. Financiability

In considering a proponent's strategy for financing a proposed project, the Siting Board considers whether a project is reasonably likely to be financed so that the project will actually go into service as planned. In the 1994 Cabot Decision, the Siting Board found that while CPC had developed a strong plan for financing the original project, one key assurance to obtaining project financing -- signed PPAs, for a significant majority of the original project's output -- was missing from an otherwise well developed financing plan. The Siting Board therefore required CPC to submit, within four years, signed and approved PPAs for at least 75 percent of the original project's electric output in order to receive final approval. The Siting Board found that upon compliance with this condition, CPC would have established that its original project was financiable. 1994 Cabot Decision, 2 DOMSB at 362.

In the current proceeding, CPC indicated its intention to finance the updated project as a merchant plant (Exh. CPC-1, at 57). CPC asserted that its parent company, Cabot Corporation, and its affiliates have extensive experience in developing, financing, and operating capital intensive projects with market risks, and that this experience ensures that the updated project would be financiable (CPC Brief at 47). CPC also asserted that the updated project's low capital and operating costs, along with its high efficiency, process hot water output, and location in a load center, give it a significant advantage in the competitive marketplace of the electric generation industry (Exh. CPC-1, at 62). CPC noted that Cabot LNG Corporation, which is a subsidiary of Cabot Corporation and the holding company for the other Cabot LNG companies, is developing a $900 million natural gas liquification plant in Point Fortin, Trinidad, using $600 million in limited recourse loans -- one of the largest limited recourse financings in Latin America (Exhs. HO-V-6; HO-V-17). The Company compared the Port Fortin LNG facility to a merchant generating facility, noting that

[22](...continued)
than § 69J¼, the Siting Board reviews the viability of the updated project in this decision.

approximately 60 percent of the revenues flowing from the LNG facility float with the New England market price for gas, translating into a significant level of market or merchant risk (Exh. HO-V-9). In addition, CPC stated that merchant plant financing, with its attendant market risk, is similar to activity in the field of commodity production, where Cabot Corporation has had extensive experience (Tr. 1, at 111). Further, CPC indicated that DOMAC has been involved in negotiating and structuring a number of gas supply agreements with power projects in New England, including the L'Energia project in Lowell, and the MASSPOWER project in Springfield (Exh. HO-V-9). Finally, the Company stated that Cabot Corporation has developed, financed, and currently operates several cogeneration projects including the Berre carbon black facility near Marseilles, France which contains a 20 MW cogeneration plant, and a plant located in Altona, Australia, which generates 16 MW (id.).

CPC stated that it currently intends to secure project financing, but that CPC may decide that it is more economical to finance the project internally (Tr. 1, at 133). CPC stated that it expects to finance the updated project with equity participation from Cabot Corporation, debt, and possibly equity from a joint partner (Exh. HO-V-10). The Company asserted that Cabot Corporation would be able, if necessary, to finance the entire project (Tr. 1, at 134). CPC reported that Cabot Corporation has approximately $2 billion in assets and $2.5 billion in market capitalization, is in good standing with credit rating agencies, with a BBB+ rating from Standard and Poors, and has a $300 million revolving credit with major international lending institutions (Exh. HO-V-10; Tr. 1, at 134).[23] CPC stated that there is a high interest in equity participation, and that if an equity partner were selected, it would be added to bring incremental value to the project (Exh. HO-V-10; Tr. 1, at 133-134).

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23 As in the 1994 Cabot Decision, CPC noted that Cabot LNG Corporation is providing funding for the development phase of the project which includes permitting, conceptual design, and securing project agreements (power purchase, fuel supply, thermal host, site lease, etc.) (Exh. CPC-1, at 61). CPC added that Cabot LNG Corporation is arranging for construction financing and would, if the project were to be internally funded, arrange for permanent financing (id.).

CPC asserted that the updated project has the ability both to compete with the going-forward costs of existing plants in New England and to bring regional economic benefits to New England by causing a reduction in the market-clearing price for energy (CPC Brief at 45). Finally, the Company indicated that a number of merchant plants in New England have recently secured limited-recourse financing, and that the financial community has confidence in lending substantial capital to merchant facilities in the Massachusetts and New England markets (Exh. HO-V-10). The Company added that financing for the updated project would be procured with the intent of maintaining debt coverage ratios acceptable to the financial community, as well as other potential commercial interests (Exh. CPC-1, at 60).[24]

The Siting Board recognizes that the updated project, like the four most recent generating projects reviewed by the Siting Board, is being financed as a merchant plant. The current nature of the power supply market is such that long-term power contracts will not be the vehicle for selling the output from the updated facilities. Therefore, as in prior cases, the Siting Board will focus on the financial experience of the proponent, its ability to market the output of the updated project, and its ability to produce reliable, low cost electricity. Evidence of signed long term contracts will not be required to establish financiability.

Here, Cabot Corporation, the parent company of CPC, has committed to finance the updated project internally if necessary. The record indicates that Cabot Corporation has a broad range of experience in the overall project development process, including financing, and has developed numerous energy facilities worldwide. Cabot Corporation also has substantial capital resources for equity investment in power projects. The range of debt coverage ratios and assumptions provided by the Company in its pro forma are generally reasonable and consistent with Siting Board reviews in prior proceedings.

Consequently, the Siting Board finds that the Company has established that its updated project is financiable.

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24 The Company provided, under confidential status, a pro forma detailing the levelized costs, debt coverage ratios, and financial assumptions of the project (Exh. CPC-1, Appendix C (confidential)).

In the 1994 Cabot Decision, the Siting Board's finding of financiability for the original project was conditioned on the submission of signed and approved PPAs which were to include capacity payments for at least 75 percent of the original project's electric output. In this proceeding the Siting Board has recognized changes in the energy market including decreased reliance on long-term contracts and has found that the updated project is financiable. Consequently, the Siting Board will no longer require CPC to comply with Condition A of the 1994 Cabot Decision, which required CPC to demonstrate financiability through the submission of signed and approved PPAs.

b. Construction

In considering a proponent's strategy for a proposed project, the Siting Board considers whether the project is reasonably likely to be constructed and go into service as planned. ANP Bellingham Power Decision, EFSB 97-1 at 69; Millennium Power Decision, EFSB 96-4, at 79; Berkshire Power Decision, 4 DOMSB at 332.

In the 1994 Cabot Decision, the Siting Board found that the Company had established that the original project was likely to be constructed within applicable time frames, based on CPC's submission of a signed engineering, procurement and construction contract ("EPC") with Fluor Daniel, Incorporated. In addition, the Siting Board required CPC to provide a signed copy of an agreement between CPC and BECo as evidence of the original project's access to the regional transmission system, and found that upon compliance with this condition, CPC would have established that its original project was likely to be constructed within applicable time frames and be capable of meeting performance objectives. 1994 Cabot Decision, 2 DOMSB at 117-118.

The EPC contract submitted in the original proceeding is no longer valid. However, the Company indicated that it is currently negotiating an EPC contract with Westinghouse Power Generation ("Westinghouse PG") (Exh. CPC-1, at 64). The Company stated that since the late 1940's, Westinghouse PG has supplied and installed over 1,000 combustion turbine power generating units, including 200 combined cycle/heat recovery units (Exh. CPC-1, at 12). CPC reported that Westinghouse's Project Implementation Department has managed the construction of an estimated total of 21,000 MW of generation since 1988, with an additional 13,000 MW currently under construction (id. at 12, 64).

CPC indicated that it expects to enter into a fixed-price turnkey contract with its EPC contractor (Exhs. CPC-1, at 64; HO-V-5). In addition, CPC stated that its EPC contract would include the following guaranteed performance criteria: net electrical output, heat rate, thermal output, compliance with all applicable environmental permits, and maximum emission level guarantees (Exh. CPC-1, at 64). The Company stated that the EPC contractor would be responsible for all design, engineering, procurement, manufacturing, delivery, construction tasks, and installation and training needed to bring the plant into operation at the guaranteed performance standards, and would be required to meet a 27 month construction schedule (id.). The Company also stated that the EPC contract will also include provisions for liquidated damages for any failure to meet the scheduled completion date, bonus/penalty provision to ensure timeliness of construction, and insurance provisions (Exh. HO-V-5).

CPC noted that the Westinghouse 501G, which is the combustion turbine proposed for the updated project, is the latest in Westinghouse's 500 line of turbines and does not have extensive commercial operating experience (Exh. HO-V-2; Tr. 1, at 86-87).[25] CPC indicated that Mitsubishi Heavy Industries ("Mitsubishi") which has been working with Westinghouse on the development, but not the marketing of this turbine, has had one 330 MW MHI 501G in operation in Japan since June 1997 (Exh. HO-V-2; Tr. 1, at 87). CPC stated that it does not have access to the specific details of the operational characteristics of the MHI 5O1G, but understands that it is operating without problems and meeting its performance expectations

[25] CPC indicated that four Westinghouse 501G turbines are scheduled for delivery in the United States by the time that the updated project is scheduled to begin commercial operation (Exh. HO-V-2).

(Tr. 1, at 88).[26] In addition, CPC stated that Westinghouse conducted a full-scale compressor test on its 501G in October 1997 with excellent performance results (Exh. HO-V-2; Tr. 1, at 88).

The Company stated that the updated project would be interconnected with the regional electric transmission grid via a 345 kV half mile underground cable to an existing substation at the Boston Edison Mystic Station (Tr. 1, at 69). CPC indicated that BECo was updating the interconnection study completed for the original 235 MW project, and that the preliminary results are encouraging (Exh. CPC-1, at 64). CPC asserted that the reinforcements needed to interconnect the updated project to the grid appear to be minimal and relatively routine in nature (Tr. 1, at 69-70). The Company indicated that based on its location in the local Boston import region, the updated project would: (1) off-load some remote transmission, thereby deferring the need for upgrades to the transmission system; (2) decrease transmission system losses; and (3) improve voltage when load is supplied locally (Tr. 1, at 84-85).

The Company indicated that the analysis was scheduled to be completed in September 1998 (Exh. HO-V-11; Tr. 1, at 69). CPC noted that the updated project is fairly high in the queue of projects waiting for a system impact study, and that none of the projects situated ahead of it in the queue are located in the Boston import region of NEPOOL (Tr. 1, at 78-79).[27]

The Company also noted that FERC Order 888 states that a transmission provider cannot refuse to interconnect a generator such as the updated project, and argued that an executed interconnection agreement therefore should no longer be a condition for Siting Board approval (CPC Brief at 52, citing Berkshire Final Decision on Compliance, EFSB 95-1, at 5

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26 CPC indicated that Mitsubishi is precluded by its licensing agreement from selling its MHI 501G turbines in the United States (Exh. HO-RR-4; Tr. 1, at 91-92). However, the Company noted that the licensing agreements between Mitsubishi and Westinghouse may change if Siemens Company acquires Westinghouse (Exh. HO-RR-4; Tr. 1, at 92).

27 The Boston import region of NEPOOL refers to an area including Boston that imports power via the transmission system under particular load and generating contingencies, and may be affected by local deficiencies for power (Tr. 1, at 79, 84).

(1997)). The Company requested that the Siting Board not condition final approval of the updated project on the submission by CPC of a signed interconnection agreement since the schedule for finalizing the interconnection agreement would not necessarily coincide with CPC's need to complete the permitting process prior to construction (CPC Brief at 52).

Finally, in the original proceeding, CPC provided a copy of a signed 30-year ground-lease agreement with MassGas, Inc. effective January 31, 1992. 1994 Cabot Decision, 2 DOMSB at 363. The Company stated that the lease agreement remains in force (Exh. CPC-1, at 58).

In the past, the Siting Board has found that a signed agreement for the design and construction of a proposed project provides reasonable assurances that the proposed project is likely to be constructed on schedule and will be able to perform as expected. ANP Bellingham Power Decision, EFSB 97-1, at 72; Millennium Power Decision, EFSB 96-4, at 82; Altresco-Pittsfield Decision, 17 DOMSC at 380.

Here, the Company has not submitted a draft or final EPC contract. The record in this proceeding indicates that Westinghouse PG has experience in the design and construction of generation plants which use technology similar to that proposed for this project and have successfully completed comparable projects. The Siting Board accepts that the Company's experience in negotiating EPC contracts for energy-related projects contributes to its ability to negotiate an acceptable final EPC contract. It also notes that the Company has stressed its intentions to provide low cost, clean power and has stated that its construction practices are structured to fulfill these objectives. However, in the absence of a final EPC contract between CPC and Westinghouse PG, the record contains no assurance that Westinghouse PG actually will be the EPC contractor for this project. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed EPC contract between CPC and Westinghouse PG, or a comparable entity, that contains provisions that provide reasonable assurance that the project would perform as a low cost, clean power producer.

The Siting Board notes that an interconnection study is being prepared, and that the Company has not yet entered into a signed interconnection agreement with BECo enabling transmission access. In the 1994 Cabot Decision, the Siting Board required CPC to provide a signed copy of an interconnection agreement between CPC and BECo as evidence that the original project had access to the regional transmission system. However, under FERC Order 888, NEPOOL has an obligation to connect the updated project with the regional transmission grid, and consequently, the outstanding interconnection issues relate to the difficulty and cost of interconnection, rather than to whether such a contract can be negotiated. The Company has addressed these issues by providing the preliminary results of its interconnection study, which indicate that only minimal upgrades would be necessary to interconnect the updated project. CPC has also demonstrated that the transmission grid would benefit from construction of new generation in the Boston import region. This lends credence to the expectations based on the preliminary results of the interconnection study, that only minimal upgrades will be needed for interconnection. Consequently, the Siting Board will no longer require CPC to comply with Condition B of the 1994 Cabot Decision, which required CPC to demonstrate access to the regional transmission system through the submission of a signed interconnection agreement.

Finally, the Siting Board notes that the proposed 501G series of turbine began commercial operation in June, 1997, and therefore has limited operating experience. However, the MHI 501G has been operating in a satisfactory manner for over a year. At the time of commercial operation of the updated project, it is likely that at least two additional generating plants will have had experience with the 501G. Nevertheless, the updated project cannot go forward as planned if there are unexpected delays in turbine development or testing. The Siting Board reiterates that a project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal (see Section IV, below). Should the 501G turbine be unable to perform substantially as expected, CPC would be required to notify the Siting Board as explained in Section IV, below.

Accordingly, upon compliance with the above conditions that the Company provide the Siting Board with a copy of a signed EPC contract between CPC and Westinghouse PG or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, the Siting Board finds that the Company will have established that its updated project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives.

The Siting Board has found that the Company has established that its updated project is likely to be financiable. The Siting Board has also found that, upon compliance with the above condition relative to a signed EPC contract CPC will have established that its updated project is likely to be constructed within applicable time frames and capable of meeting the Company's performance objectives. Accordingly, the Siting Board finds that, upon compliance with the above condition, the Company will have established that its updated project meets the Siting Board's first test of viability.

3. Operations and Fuel Acquisition

a. Operations

In determining whether a proposed NUG project is likely to be viable as a reliable, least-cost source of energy over the planned life of the proposed project, the Siting Board evaluates the ability of the project proponent or other entities to operate and maintain the facility in a manner which ensures a reliable energy supply. ANP Bellingham Power Decision, EFSB 97-1, at 74; Millennium Power Decision, EFSB 96-4, at 84; Altresco-Pittsfield Decision, 17 DOMSC at 381-382. In a case where the proponent has relatively little experience in the development and operation of a major energy facility, that proponent has been asked to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. These tasks have historically been enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the facility. ANP Bellingham Power, EFSB 97-1, at 74; Millennium Power Decision, EFSB 96-4, at 84; Altresco-Pittsfield Decision, 17 DOMSC at 382-383.

In the 1994 Cabot Decision, the Siting Board found that CPC had established that its updated project was likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales agreement, based on CPC's submission of a signed O&M contract with Mission Operation and Maintenance. This contract is no longer valid.

In the current proceeding, CPC stated that it is in the process of negotiating an O&M contract complete with bonus, penalty, and incentive provisions with Westinghouse Operating Services Company ("Westinghouse OSC"), a qualified vendor (Exhs. CPC-1, at 66; HO-V-5). The Company stated that Westinghouse OSC provides a full array of technical services, field services, repair training, and other operating and maintenance services (Exh. CPC-1, at 66). CPC reported that Westinghouse OSC currently provides O&M services at six combined cycle gas facilities, representing approximately 1,550 MW (Exh. HO-V-7). Further, CPC indicated that Westinghouse OSC has significant O&M experience with simple cycle gas facilities throughout the world (id.). The Company stated that the average availability reported by Westinghouse OSC for the projects that it operates is over 94 percent (id.). In addition, CPC stated that it would be advantageous to have the major equipment supplier be both the O&M contractor and the EPC contractor (Tr. 1, at 103).

The Company asserted that the terms of the O&M agreement would be designed to create incentives for the operator to maintain the updated project's longevity, availability, and maximum output without sacrificing environmental considerations or community relations (Exhs. CPC-1, at 66; HO-V-5). CPC provided a summary of its O&M program, which would include procedures for: (1) normal plant O&M functions; (2) catastrophic avoidance; (3) emergency preparedness; (4) incremental improvement in the condition and capability of the facility; and (5) equipment status monitoring and documentation (Exh. CPC-1, at 67-68). Specifically, the Company stated that it would implement a performance-based fee system to address plant availability, plant efficiency, heat-rate degradation, net power output, and safety practices (Exh. HO-V-5).

The Company asserted that it expects to sign a final O&M agreement by the end of 1998 which is prior to financial closing and well before the start-up of commercial operation

(Exh. CPC-1, at 67; CPC Brief at 55). CPC stated that the Westinghouse 501G has a six year maintenance cycle, and that the term of the O&M contract therefore will be either six or 12 years (Tr. 1, at 104). The Company indicated that, in the event that Westinghouse OSC is not selected as the O&M contractor, CPC will evaluate and compare the benefits of contracting O&M services with: (1) a turnkey construction contractor with O&M experience, (2) a power island vender, or (3) an electric utility or non-utility generator operating subsidiary (Exh. CPC-1, at 67).

In past cases, the Siting Board has found that an acceptable, executed O&M contract with an appropriate, experienced entity provided sufficient assurance that a project is likely to be operated and maintained in a manner consistent with reliable performance objectives. ANP Bellingham Power Decision, EFSB 97-1, at 75; Millennium Power Decision, EFSB 96-4, at 85; Altresco-Pittsfield Decision, 17 DOMSC at 382. The Siting Board notes that Cabot Corporation, the parent company of CPC, has documented that it has experience in contracting for the operation of a variety of energy projects, although not necessarily of the type and scale of the updated project, and has indicated that it intends to contract with an experienced vendor to operate the updated project. In addition, CPC has provided a summary of its anticipated O&M plan. However, in the absence of a final O&M contract between CPC and Westinghouse OSC, the record contains no assurance that Westinghouse OSC actually will be the O&M contractor for this project. Therefore, the Siting Board requires the Company to provide the Siting Board with a copy of a signed O&M contract between CPC and Westinghouse OSC, or a comparable entity, that contains provisions that provide reasonable assurance that the project would perform as a low cost, clean power producer.

Accordingly, upon compliance with the above condition that the Company provide the Siting Board with a copy of a signed O&M contract between CPC and Westinghouse OSC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, the Siting Board finds that the Company will have established that its updated project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

b. Fuel Acquisition

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

In the 1994 Cabot Decision, the Siting Board required CPC to provide a copy of the contract or any other agreement between the Company and Exxon Corporation ("Exxon") or any of Exxon's successors, regarding the supply of distillate oil to the original project, and found that upon compliance with this condition, CPC would have established that its fuel acquisition strategy reasonably ensured a low-cost, reliable source of energy over the likely term of project PPAs. The Siting Board based its conclusion on: the Company's articulation of a reasonable long-term primary fuel supply plan; the location of the original project adjacent to the fuel supply; and CPC's signed gas purchase contract with DOMAC with (1) a low initial fuel price, and (2) stable prices throughout the life of the original project. With respect to back-up fuel supply plans, the Siting Board found that the Company would utilize natural gas or distillate oil. The Siting Board also noted that the location of the original project was advantageous with respect to each of the back-up fuel supply options and that pipeline interconnects -- terminating at the original project -- would enable delivery of each option. The gas purchase contract with DOMAC provided that DOMAC would be responsible to supply natural gas to the original project in the event that it was unable to supply vaporized LNG. 1994 Cabot Decision, 2 DOMSB at 369-370.

In the current proceeding, CPC stated that its original contract with DOMAC does not provide CPC with the flexibility it needs in the current competitive energy market (Exh. CPC-1, at 68, 70-71; CPC Brief at 57). However, CPC stated that it still plans to purchase all of its fuel requirements from DOMAC, located adjacent to the CPC updated project (id.).[28] CPC reported that it expects to execute a new fuel contract with DOMAC by

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[28] In the 1994 Cabot Decision the Company stated that, since the original project would be located adjacent to the DOMAC Terminal, there would be no need for fuel (continued...)

the end of 1998, and noted that its affiliation with DOMAC provides for faster contract negotiations (Tr. 1, at 145). The Company indicated that it will enter into formal agreements documenting its long-term supply arrangement as the updated project progresses (Exh. CPC-1, at 71; Tr. 1, at 145).

CPC stated that Distrigas Corporation ("Distrigas")[29] would be responsible for importing the DOMAC volumes to the DOMAC Terminal, where it would be received and vaporized by DOMAC (Exh. HO-V-13). The Company indicated that DOMAC is actively marketing its gas supply to other Northeast and New England electric generators (Exh. CPC-1, at 10). CPC further reported that DOMAC is presently supplying gas to two Massachusetts non-utility generators -- MASSPOWER and L'Energia (id.).

The Company stated that the deliverability of LNG to the DOMAC Terminal is backed from a portfolio of supply that includes LNG from Algeria (Sonatrach), Trinidad (Atlantic LNG) and other LNG suppliers (Exh. HO-V-13). In addition, CPC indicated that there is a growing spot market for LNG, opening up additional short-term supplies of LNG to DOMAC (id.). The Company stated that the DOMAC facility is scheduled to receive between 30 and 40 of LNG cargoes a year,[30] of which six, equivalent to almost 60,000 MMBtu, would be

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[28](...continued)

transportation by an outside pipeline/distribution company since the LNG is vaporized at the DOMAC Terminal. Other than the short interconnection piping which would be located on the DOMAC Terminal property and extend to the proposed site adjacent to the DOMAC Terminal, no new equipment would be required to provide the vaporized LNG to CPC. Regarding fuel costs, there would be no pipeline transportation charges because the original project would be located adjacent to the DOMAC Terminal. 1994 Cabot Decision, 2 DOMSB at 367.

[29] Distrigas is a sister company to DOMAC. See Section II.A, for a description of the corporate affiliations of the Cabot Corporation.

[30] The Company indicated that each cargo contains 2.7 trillion BTUs of gas (Tr. 1, at 117). The Company asserted that to its knowledge, neither the Coast Guard nor MassPort has expressed concerns about the number of LNG tankers supplying the DOMAC facility (id. at 120).

consumed by the updated project (Exh. HO-V-16; Tr. 1, at 117). CPC asserted that the combined Algerian and Trinidad supplies alone would allow DOMAC to sustain an average daily sendout greater than 250,000 MMBtu of vaporized LNG from the Everett LNG terminal (Exh. HO-V-16). CPC explained that the expected level of LNG supplies to DOMAC is made possible by construction of the Atlantic LNG plant, a Trinidad LNG facility that is scheduled to be completed in the spring of 1999 (Exh. HO-V-15).[31]

CPC stated that in the unlikely event that DOMAC was temporarily unable to supply vaporized LNG to the updated project, DOMAC would provide either pipeline gas or other vaporized LNG to the project (Exh. CPC-1, at 71). The Company stated that the updated project and the DOMAC LNG terminal are both located at the intersection of the two interstate pipelines serving New England -- Algonquin Gas Transmission Company and Tennessee Gas Pipeline Company -- and adjacent to Boston Gas' LNG facilities (Exh. CPC-1, at 71). The Company pointed out that FERC has approved an expansion by Tennessee of its pipeline system from the end of the Revere lateral into Everett (Tr. 1, at 123).

In considering an applicant's fuel acquisition strategy, the Siting Board considers whether such a strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the proposed project. ANP Bellingham Decision, EFSB 97-1, at 78; Millennium Power Decision, EFSB 96-4, at 90; Berkshire Power Decision, 4 DOMSB at 343. The Siting Board has recognized that, in considering a petitioner's fuel acquisition strategy, it is appropriate to consider the need for flexibility, the expected shorter time frame of PPAs in a restructured electric industry, and the industry-wide shift away from long-term gas supply contracts. ANP Bellingham Decision, EFSB 97-1, at 78; Millennium Power Decision,

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31 The Company stated that construction of the Atlantic LNG plant is currently on schedule and that the date of the first delivery to DOMAC is now projected to be between March 1, 1999 and May 29, 1999, approximately two years prior to the scheduled commercial operation date of the updated project (Exh. HO-V-15). Cabot Trinidad LNG limited, a subsidiary of Cabot Corporation, holds a ten percent equity interest in the Atlantic LNG plant (Exhs. HO-V-17; CPC-1, at 69).

EFSB 96-4, at 90; Berkshire Power Decision, 4 DOMSB at 343. Nevertheless, the proponent must demonstrate that a low-cost, reliable fuel supply will be available to a proposed project in order to determine that a proposed project will be capable of providing a necessary energy supply consistent with its mandate.

In past decisions, the Siting Board generally has reviewed final fuel transportation and/or supply contracts between proponents and pipeline companies. While the Siting Board has not required proponents to submit signed long-term fuel supply contracts in recent cases, it generally still has required firm transportation contracts from a major interconnection point as assurance that a proponent's gas supply strategy is viable.

Here, the Company has presented a fuel acquisition strategy that is similar to that presented in the original petition, with two exceptions: (1) CPC currently does not have in place a long-term LNG supply contract with its supplier, DOMAC; and (2) CPC no longer intends to use oil as a back-up fuel. The Company has stated that its affiliate DOMAC will be the principal supplier for all of the updated project's fuel requirements. The Company plans to have its gas supply contract with DOMAC in place prior to the start of construction. Distrigas has procured significant additional LNG gas supplies from a new facility being constructed in Trinidad, of which Cabot Corporation is a part owner. Further, the Company has provided information demonstrating that there are sufficient, available DOMAC supplies to be allocated to CPC exclusively and that the location of the updated project adjacent to the fuel supply is advantageous and cost efficient. In addition, DOMAC has demonstrated that it has experience in procuring fuel for comparable facilities including two facilities in Massachusetts.

In regard to a back-up fuel supply, CPC has a number of options with respect to receiving an alternative supply of gas through DOMAC, via Tennessee, Algonquin or Boston Gas. In addition, the LNG spot market is available to supplement existing LNG supplies. Therefore, the decision to forgo oil as a back-up fuel still ensures a reliable and sufficient back-up fuel supply, while contributing to increased environmental benefits.

It is likely that the fuel supplies selected by the Company will be low cost and reliable, due to DOMAC's location adjacent to the updated project, and the committed long term relationship between the corporate entities. Accordingly, the Siting Board finds that the Company has established that its fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the updated project.

However, the Company has not yet entered into a final contract for gas supply. The Siting Board's conclusions regarding the Company's fuel acquisition strategy assume that the final contracts will be consistent with the fuel supply plan outlined during this proceeding. In Section IV, below, the Siting Board requires CPC to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into that issue. Therefore, the Company shall notify the Siting Board if contracts are executed that provide for fuel transportation and supply arrangements other than those considered in this analysis, and submit to the Siting Board a discussion of the changed arrangements and explain how such arrangements would affect the cost and reliability of the project's gas supply.

In the 1994 Cabot Decision, the Siting Board found that the fuel acquisition strategy of the original project was to be conditioned on the submission of a copy of the contract or any other agreement between the Company and Exxon or any of Exxon successors, regarding the supply of distillate oil to the original project. In the updated project, the Company will not use oil as a back-up fuel. Consequently, the Siting Board will not require CPC to comply with Condition C of the 1994 Cabot Decision, which required submission of a contract or agreement demonstrating a back-up fuel supply.

The Siting Board has found that, upon compliance with the above condition relative to a signed O&M, contract CPC will have established that its updated project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. The Siting Board has also found that CPC's fuel acquisition strategy reasonably ensures a low-cost, reliable source of energy over the planned life of the updated project. Accordingly, the Siting Board finds that the Company has established that its updated project meets the Siting Board's second test of viability.

4. Conclusions on Project Viability

The Siting Board has found that, upon compliance with the conditions in Sections II.B.2 and II.B.3 above, CPC will have established that its updated project (1) is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) is likely to operate and be a reliable, least-cost source of energy over the planned life of the updated project.

Accordingly, the Siting Board finds that, upon compliance with the aforementioned conditions, CPC will have established that its updated project is likely to be a viable source of energy.

III. ANALYSIS OF THE UPDATED PROJECT

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. Further, G. L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In implementing this statutory mandate and requirement, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. 1993 BECo Decision, EFSB 90-12/90-12A at 27. The Siting Board accomplishes this through a review of the applicant's site selection process, followed by a review of the environmental impacts, costs and reliability of the proposed facilities.

In the 1994 Cabot Decision, the Siting Board reviewed CPC's site selection process, including the consistency of the Company's proposal with the Siting Board's Coastal Zone Facility regulations.[32] The Siting Board found that: (1) CPC had developed a reasonable set of criteria for identifying and evaluating alternative sites; (2) CPC had appropriately applied a reasonable set of criteria for identifying and evaluating alternatives in a manner that ensured that it had not overlooked or eliminated any clearly superior sites; and (3) CPC was not required to provide an alternative site with some measure of geographic diversity.[33] 1994 Cabot Decision, 2 DOMSB at 388. The Siting Board also found that CPC had 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. Id. The Siting Board

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32 The Updated Project lies within the boundaries of the Massachusetts coastal zone, which extends approximately three quarters of a mile inland from the Mystic River. 1994 Cabot Decision, 2 DOMSB at 375.

33 The Siting Board based this finding on the original project's status as a cogeneration facility located fully within the boundaries of the principal thermal host. 1994 Cabot Decision, 2 DOMSB at 386.

therefore found that CPC had considered a reasonable range of practical facility siting alternatives. Consistent with the Hearing Officer's December 23, 1997 procedural order, the Siting Board does not revisit these findings in this decision.

A. Description of Updated Project

CPC proposes to construct a 350-MW gas-fired, combined-cycle cogeneration facility within the IEIP which is located in the City of Everett and bordered, generally, by the Island End River, the Mystic River, Route 16 and Route 66 (Exh. CPC-1, at 1; 1994 Cabot Decision, 2 DOMSB at 371). The proposed site is currently occupied by a vacant warehouse and truck loading areas and is owned by MassGas, Inc., an affiliate of Cabot. 1994 Cabot Decision, 2 DOMSB at 371. The 5.2 acre proposed site is surrounded by industrial uses including the DOMAC LNG Marine Terminal and an unused rail spur to the northwest, a warehouse to the northeast, and a cement storage facility and sand and gravel operation to the south. Id. See Figure 1.

The major components of the updated project consist of: (1) a 230 MW high temperature combustion turbine-generator with dry low-NOx combusters; (2) an HRSG; (3) a 120 MW steam turbine-generator; (4) an SCR system; (5) an air-cooled condenser; (6) a turbine air inlet chiller; and (7) a 150-foot exhaust stack (Exh. CPC-1, at 3-4). Additional components include a 345 kV standard air-insulated substation, and an ammonia storage tank (id.). Relatively low temperature exhaust steam would be converted to hot water and piped to the DOMAC Terminal where it would be used to vaporize LNG (Tr. 1, at 140-143).[34] Electricity output would be transmitted to the Boston Edison Mystic Station substation via an approximately one-half mile, underground, 345 kV transmission line (Exh. CPC-1, at 3-5).

The primary fuel for the updated project would be LNG supplied by DOMAC via a pipeline from the DOMAC Terminal. At times when vaporized LNG is not available,

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34 The Company indicated that, currently, LNG is vaporized by use of gas-fired boilers which require approximately 1.8 percent of the vaporized output of the DOMAC Terminal (Tr. 1, at 140-141).

equivalent volumes of natural gas delivered via existing pipeline facilities connected to the DOMAC Terminal would be employed (id. at 3, 69, 71).

The updated project would cost approximately $241 million in 2000 dollars (id. at 73).

B. Environmental Impacts, Cost and Reliability of the Updated Project

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed site for the project is superior to the noticed alternative on the basis of balancing cost, environmental impact and reliability of supply. ANP Bellingham Decision, EFSB 97-1, at 92; Millennium Power Decision, EFSB 96-4, at 106; Berkshire Gas Company, 23 DOMSC at 294, 324 (1991). In cases, such as the instant case, where a noticed alternative is not required, the facility proponent still must demonstrate that the proposed site for the facility will minimize environmental impacts and that an appropriate balance will be achieved among conflicting environmental concerns as well as among environmental impacts, cost and reliability. 1994 Cabot Decision, 2 DOMSB at 388-389; Altresco Lynn Decision, 2 DOMSB at 176 (1993); Berkshire Gas Company, 23 DOMSC at 294, 324 (1991).

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost and reliability. ANP Bellingham Decision, EFSB 97-1, at 92-93; Millennium Power Decision, EFSB 96-4, at 106; EEC Decision, 22 DOMSC at 334, 336. A facility proposal which achieves that appropriate balance is one that meets the Siting Board's statutory requirement to minimize environmental impacts. ANP Bellingham Decision, EFSB 97-1, at 92; Millennium Power Decision, EFSB 96-4, at 106; EEC Decision, 22 DOMSC at 334, 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. ANP Bellingham Decision, EFSB 97-1, at 93; Millennium Power Decision, EFSB 96-4, at 106; EEC Decision, 22 DOMSC at 334, 336. Compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. ANP Bellingham Decision, EFSB 97-1, at 93; Millennium Power Decision, EFSB 96-4, at 106; EEC Decision, 22 DOMSC at 334, 336. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in specific facility proposals. ANP Bellingham Decision, EFSB 97- 1, at 93; Millennium Power Decision, EFSB 96-4, at 106; EEC Decision, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost, and reliability trade-offs associated with a particular decision must be clearly described and consistently reviewed from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, costs and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination.[35] ANP Bellingham Decision,

[35] The Siting Board notes that project proponents are required to submit to the Siting Board a description of the environmental impacts of the proposed facility. G.L. c. 164, § 69J. Specifically, Siting Board regulations require that a proponent of a generating facility provide a description of the primary and alternatives sites and the surrounding areas in terms of: natural features, including among other things, topography, water resources, soils, vegetation, and wildlife; land use, both existing and proposed; and an evaluation of the impacts of the facility in terms of its effect on the (continued...)

EFSB 97- 1, at 93-94; Millennium Power Decision, EFSB 96-4, at 107; 1993 BECo Decision, EFSB 90-12/90-12A at 31-32. The Siting Board can then determine whether environmental impacts have been minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs, and reliability has been achieved. ANP Bellingham Decision, EFSB 97- 1, at 94; Millennium Power Decision, EFSB 96-4, at 107; 1993 BECo Decision, EFSB 90-12/90-12A at 32.

Accordingly, in the sections below, the Siting Board examines the environmental and cost impacts of the proposed facilities at the Company's proposed site to determine: (1) whether environmental impacts would be minimized at the site; and (2) whether an appropriate balance would be achieved at the site among conflicting environmental concerns as well as among environmental impacts, cost and reliability.[36]

[35](...continued)

natural resources described above, land use, visibility, air quality, solid waste, noise and socioeconomics. 980 C.M.R. § 704(8)(e).

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

[36] The Siting Board notes that in the current proceeding, there are not any differential reliability issues to be balanced against environmental and cost issues.

2. Environmental Impacts of the Updated Project

a. Air Quality

In the 1994 Cabot Decision, the Siting Board found that CPC had provided adequate support for its assertion that emissions of criteria pollutants and other regulated pollutants from the updated project would be minimized, and that emissions of criteria pollutants would have acceptable impacts on existing air quality. The Siting Board also found that with the implementation of a specific offset plan required by the Siting Board, the environmental impacts of the CO_2 emissions from the updated project would be minimized consistent with minimizing cost. The Siting Board therefore found that, with the implementation of CPC's proposed Best Available Control Technology ("BACT"), and with the implementation of the Siting Board condition regarding a CO_2 mitigation plan, the environmental impacts of the updated project would be minimized with respect to air quality. 1994 Cabot Decision, 2 DOMSB at 402, 403.

(1) Description

The Company asserted that the stack emissions from the updated project would be adequately minimized and would have acceptable impacts on air quality (CPC Brief at 76). CPC asserted that the emissions of the updated project are significantly less than those of the original project, due primarily to the elimination of oil as a back-up fuel, the use of more efficient turbine and air pollution control equipment, and the installation of a carbon oxidation catalyst (Exhs. CPC-1, at 76; HO-E-13). CPC indicated that the air pollution control technologies proposed for the project and the resultant emissions are equal to or better than those proposed for similar projects recently approved by the Siting Board (Exh. CPC-1, at 76). The Company provided estimates of the quantity of pollutants that would be emitted from the updated project based on emission guarantees for the Westinghouse 501G gas turbine (Exh. HO-E-10).

CPC explained that new Clean Air Act regulatory requirements have been promulgated since the 1994 Cabot Decision was issued (Exh. CPC-3, at 4-23). Specifically, the updated project now is classified as a major source for Nitrogen Oxide ("NOx") under Non-attainment New Source Review ("NSR") (id.). The updated project therefore must meet emission controls associated with Lowest Achievable Emission Rate ("LAER") and must offset its NOx emissions (id.). Further, the updated project is now subject to Prevention of Significant Deterioration ("PSD") regulations for NOx, CO, Volatile Organic Compounds ("VOC") and Particulate Matter ("PM_{10}"); therefore, these criteria pollutants must meet the standards for BACT (id.).

The Company provided data indicating that, for all criteria pollutants except VOC, annual emissions would be less under the updated project than the original project (Exh. CPC-1, at 75).[37] The Company explained, however, that although the emissions as measured in tpy would be less, maximum concentrations of NOx, CO, and PM_{10} would be greater under the updated project due to its lower stack height (Tr. 2, at 75). CPC asserted that the updated project's emissions are well within acceptable levels, that ambient impacts would be well below applicable standards, guidelines, and PSD increments, and that for many pollutants and averaging periods, the impacts would be below the Significant Impact Level criteria ("SIL") (id.; Exh. CPC-2, at 4-33).

The Company asserted that it will use dry low-NOx combusters and SCR to achieve a 3.5 ppm emission rate for NOx (Exhs. CPC-1, App. H at 2; CPC-3, at 4-26 to 4-27). The Company provided copies of correspondence between CPC and MDEP concerning (1) the use of a new NOx control technology called SCONOx, and (2) attainment of a new LAER standard for NOx emissions of 2.5 ppm with a zero ppm emission rate for ammonia slip (Exhs. HO-E-8; HO-RR-9 (Atts. 1, 2, and 3)). The Company stated that it is still reviewing with MDEP, in the context of CPC's air permit application, the issues of a lower LAER for NOx and the ability to eliminate ammonia slip (Tr. 2 at 81-91).

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[37] The emissions level changes are as follows: NOx decreased from 207 tpy to 145 tpy; CO decreased from 98 tpy to 93 tpy; Sulfur Dioxide ("SO_2") decreased from 39 tpy to 11 tpy; PM_{10} decreased from 46 tpy to 44 tpy, and VOC increased from 16 tpy to 44 tpy (Exh. CPC-1, at 75).

In regard to non-criteria pollutants, CPC indicated that the updated project would essentially no longer emit beryllium, fluoride, and mercury; sulfuric acid mist would be reduced; and ammonia and CO_2 emissions are expected to increase over those identified in the original project (Exh. CPC-1, App. H at 2). CPC stated that the threshold effects limits ("TELs") and allowable ambient limits ("AALs") established by MDEP as guidelines for air toxics, which here apply to ammonia and sulfuric acid, show that air toxic impacts of the updated project would not exceed the TELs and AALs (Exh. CPC-2, at 4-34).

The Company stated that it is required by MDEP to provide NOx offsets at a minimum ratio of 1.2 to 1.0 in order to comply with non-attainment NSR for NOx (Exhs. CPC-1, at 77; CPC-2, at 5-1). The Company explained that it will be obligated to obtain MDEP-certified Emission Reduction Credits ("ERCs") in an amount five percent greater than needed based on the 1.2 to 1.0 ratio (Exh. CPC-1, at 77). CPC stated that it therefore would obtain, prior to the operation of the project, ERCs totalling 1.26 times the maximum annual NOx emissions, or 183 tons of offsets (id.). CPC indicated that it has discussed the possible purchase of either shutdown credits or a stream of ERCs with Boston Edison, New England Power and Eastern Utility Associates (id.; Exh. HO-E-9). Further, CPC stated that it anticipates future discussions regarding NOx offsets with other entities who have purchased investor owned utility electric facilities (Exh. HO-E-9). The Company stated that its first preference is to purchase shutdown credits, and that it would purchase discrete credits as a second choice (id.).

The Company indicated that the updated project would emit up to 1.25 million tpy of CO_2, an increase of 307,000 tpy over the 943,000 tpy estimated for the original project (Exh. CPC-1, at 77). CPC stated that the estimated increase in CO_2 emissions resulted from the increased capacity of the updated project, but asserted that the increase had been minimized by the elimination of oil as a back-up fuel and by the use of a more efficient turbine technology (id.). The Company has proposed to make contributions to cost-effective mitigation programs during the first five years of the project at a net present value equivalent to the total amount that would offset one percent of the annual CO_2 emissions over a 20-year period at the cost of $1.50 per ton (id.; Tr. 2, at 91). CPC indicated that it would work in consultation with the

Siting Board to select cost-effective mitigation programs toward which the contribution would be applied (Exh. CPC-1, at 77; Tr. 2, at 91). The Company asserted that its proposed CO_2 mitigation approach complies with the standards set forth by the Siting Board in the Dighton Power Decision, EFSB 96-3, at 37-43 (Exh. CPC-1, at 77).

(2) Analysis

The Company has demonstrated that emissions of criteria and other pollutants from the updated project at the proposed site would have acceptable impacts on existing air quality. The Company has used reasonable and appropriate air modelling techniques to assess the impacts of emissions from the updated project. The record shows that the updated project would include a highly efficient combustion turbine with natural gas as the sole fuel. Additionally, the Company has indicated that the updated project would incorporate advanced emissions control technologies.

The Company has presented offset analyses for NOx and CO_2 -- pollutants which potentially contribute to regional ground-level ozone concerns and international climate change concerns, respectively. With respect to NOx, the Company has established that it has a viable plan in place to obtain NOx ERCs consistent with non-attainment NSR and MDEP requirements.

In the Dighton Power Decision, the Siting Board set forth a new approach to the mitigation of CO_2 emissions that required generating facilities to make a monetary contribution, within the early years of project operation, to one or more cost-effective CO_2 offset programs, with such program(s) to be selected in consultation with the Siting Board Staff. EFSB 96-3, at 42-43.[38] In Dighton, the Siting Board expressed an expectation that the contributions of future project developers would reflect that set forth in Dighton, which was

38 Previously, the Siting Board required project proponents to commit to a specific program of CO_2 mitigation, such as a tree planting or forestation program, designed to offset a percentage of project CO_2 emissions within the early years of facility operation. See Berkshire Power Decision, 4 DOMSB at 373-374.

based on an offset of one percent of annual facility CO_2 emissions, at $1.50 per ton, to be donated in the early years of facility operation. Id. at 43.

With respect to mitigation of CO_2, the Company has proposed to contribute an amount, based on the updated project's annual maximum CO_2 emissions over 20 years of operation, that would be consistent with those ordered in recent generating facility cases. Based on projected maximum annual CO_2 emissions of 1.25 million tpy for the updated project, the total contribution requirement would be $375,000. Therefore, the Siting Board requires the Company to provide CO_2 offsets through a total contribution of $398,185 to be paid in five annual installments during the first five years of project operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board.[39] Alternatively, the Company may elect to provide the entire contribution within the first year of project operation. If the Company so chooses, the CO_2 offset requirement would be satisfied by a single first-year contribution based on the net present value of the five year amount to a cost-effective CO_2 offset program or programs to be selected upon consultation with the Staff of the Siting Board.[40]

Accordingly, the Siting Board finds that, with implementation of the foregoing NOx and CO_2 offset measures, the environmental impacts of the updated project at the proposed site would be minimized with respect to air quality.

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39 The contribution is based on offsetting 250,000 tons over 20 years at $1.50 per ton. The 20-year amount of $375,000 is first distributed as a series of payments to be made over the first five years of project operation, then adjusted to include an annual cost increase of three percent. Annual contribution amounts would be distributed as follows: year one $75,000; year two $77,250; year three $79,568; year four $81,955; year five $84,413. See ANP Bellingham Decision, EFSB 97-1, at 103-104; Millennium Power Decision, EFSB 96-4, at 114, 117-118.

40 The net present value amount is to be based on discounting, at ten percent, the five annual payment totalling $398,000. See ANP Bellingham Decision, EFSB 97-1, at 104; Millennium Power Decision, EFSB 96-4, at 117-118. The single up-front payment would be due by the end of the first year of operation, at a cost of $330,215

b. Noise

In the 1994 Cabot Decision the Siting Board found that the operation of the updated project would result in a maximum residential receptor noise increase of three decibels ("dBA") -- a level that not only would be within the MDEP ten decibel guideline, but would be less than half that amount. The 1994 Cabot Decision recognized that existing ambient residential noise levels were close to the highest levels addressed by the Siting Board compared to those in earlier previous reviews of proposed generating facilities. Altresco Lynn Decision, EFSB 91-102, at 188; 1993 BECo Decision, EFSB 90-12/90-12A at 100; Enron Decision, 23 DOMSC at 210-211.

The 1994 Cabot Decision noted that the Company did not expect that the three dBA maximum residential increase would be guaranteed by the contractor and that the Company did not expect to take any action, barring problems, if the actual noise increases were slightly higher than the projected three dBA increase. Given that the existing ambient noise levels in residential areas in the vicinity of the original project were higher than the levels identified by the EPA as requisite to protect public health, the Siting Board concluded that increases above the projected levels would not be acceptable. Finally, with respect to construction noise, the Siting Board noted in the 1994 Cabot Decision that since the calculated noise levels of most construction activity at the nearest residence would exceed existing daytime noise levels, construction noise could potentially impact nearby residential areas.

Therefore, in order to minimize noise impacts of community noise levels, in the 1994 Cabot Decision the Siting Board required that CPC: (1) incorporate all proposed mitigation so that the continuous noise increase from the operation of the updated project would be no more than three decibels at any residence;[41] (2) refrain from conducting construction that generates

[41] In the 1994 Cabot Decision, the Company indicated that the greatest residential noise impacts would occur at Admiral's Hill in Chelsea; that Admiral's Hill also had the highest background noise levels of all residential receptors, and that minimum ambient noise levels, would increase by three dBA, from 51 dBA to 54 dBA with operation of (continued...)

significant noise before 8:00 a.m.;[42] and (3) confine all primary construction activity to between the hours of 6:30 a.m. and 5:30 p.m., Monday through Saturday, except as necessary for structural integrity or safety reasons. The Siting Board therefore found that, with the implementation of the aforementioned conditions, the environmental impacts of the original project would be minimized with respect to noise impacts. 1994 Cabot Decision, 2 DOMSB at 408.

In this proceeding, the Company asserted that it would undertake significant noise control measures to meet the conditions set forth in the 1994 Cabot Decision, and that the impacts of the updated project therefore would be minimized with respect to noise (Exh. CPC-1, App. I, at 8). The Company further stated that the noise impacts of the updated project would comply with MDEP regulations and policies that restrict (1) increases in the broadband sound level to ten dBA above the pre-existing ambient level, and (2) production of a pure tone sound (CPC Brief at 79).

The Company indicated that the existing noise environment around the updated project site is essentially unchanged from that described in its original petition (Exh. CPC-1, App. I at 1). CPC conducted an updated study of noise impacts study at the two most sensitive residential locations and at the nearest property line (id.). The Company indicated that the highest L_{90} noise increase at a residential receptor would continue to be at Admiral's Hill, where noise levels would increase by four dBA, from 50 dBA to 54 dBA (id. at 6). Noting that an increase of three dBA is the minimum increase that is perceptible to the human ear, the Company stated that the projected increase of four dBA would result in a barely perceptible change in community noise (id. at 7).

With regard to noise impacts at the property line, CPC indicated that L_{90} noise increases would range from five dBA to nine dBA, and that the maximum resultant noise level would be

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[41](...continued)
the updated project. 2 DOMSB at 405.

[42] The Company explained that significant construction noise consists of for example, pile driving and heavy earth moving (Tr. 2, at 51).

75 dBA at the northeast property line (Exh. CPC-3(S)). CPC stated that facility noise at the adjacent indoor industrial locations would be negligible due to the noise reduction effect of building walls and existing noise within those adjacent industrial facilities (id. at 7). Further, CPC stated that combined facility and background noise levels at these facility locations would be one to six dBA lower than criteria that protect the most sensitive indoor use (Exhs. CPC-3(S); HO-E-6).[43]

CPC asserted that it would guarantee that the updated project would not result in any noise increase of more than four dBA over the existing ambient noise levels at the residential receptors (Tr. 2, at 44). CPC explained that the EPC contract would include a guarantee based on the MDEP ten dBA limitation in residential areas (Exh. HO-V-8; Tr. 2, at 44). However, the Company asserted that it has selected design and noise mitigation strategies that would ensure a maximum noise increase of four dBA at residential receptors and added that the contractor would install the equipment the Company had specified (Tr. 2, at 44-50).

The Company estimated an additional cost of $1.5 million to reduce the proposed noise increase from four dBA to three dBA (Exh. HO-RR-8). In addition, the Company stated that, the additional mitigation that would be achieved by an expenditure of $1.5 million would not result in any change in the nighttime total L_{eq} noise level at the Admiral's Hill receptor (id.).

CPC stated that it is very difficult to quantify construction noise impacts due to the nature of construction activity (Exh. CPC-1, App. I at 6). The Company stated that it would comply with the operational limits placed on the construction activity in the 1994 Cabot Decision (id.; CPC Brief at 80).

As discussed above, the Siting Board recognized in the 1994 Cabot Decision that the operation of the updated project would result in a maximum residential noise receptor increase of three dBA, less than half of the MDEP guideline. The four dBA maximum noise increase

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43 The Company indicated that the Institute of Noise Control Engineering recommends an L_{eq} of 48 dBA indoor criterion for offices in industrial areas, and added that the equivalent outdoor noise level is 73 dBA based on adding 25 dBA for shell attenuation (Exh. HO-E-6). The Company stated that the 73 dBA criterion is a conservative figure as OSHA uses 115 dBA as an outdoor equivalent (id.).

with the updated project would still comport with that guideline, and further would still be comparable to or lower than the residential noise increase estimated in the earlier Enron project review. 1994 Cabot Decision, 2 DOMSB at 407, citing Enron Decision, 23 DOMSC at 208, 211. Further, CPC here has committed that the maximum increase over existing ambient noise levels at residential receptors will not exceed the calculated amount of four dBA.

The Siting Board notes that although the now proposed four dBA increase is larger than the three dBA increase accepted in the 1994 Cabot Decision, the impact falls below what the Siting Board has accepted in the past. Further, the additional noise mitigation necessary to attain a three dBA increase would not warrant an additional expenditure of $1.5 million dollars. Finally, with the limits on the working hours contained therein, the Siting Board reaffirms its finding in the 1994 Cabot Decision that construction noise impacts would be minimized (see Section III.B.2.j, for a discussion concerning vibration and construction).

Therefore CPC shall: (1) incorporate all updated mitigation as described in the 1994 Cabot Decision so that the continuous noise increase from the operation of the updated project is no more than four decibels at any residence; (2) refrain from conducting construction activities that generate significant noise before 8:00 a.m.; and (3) confine all primary construction activity to between the hours of 6:30 a.m. and 5:30 p.m., Monday through Saturday, except as necessary for structural integrity or safety reasons.

Accordingly, with implementation of the aforementioned mitigation measures, the Siting Board finds that the environmental impacts of the updated project will be minimized with respect to noise.

c. Water Use and Wastewater Discharge

In the 1994 Cabot Decision the Siting Board found that the Company: (1) had documented that there was an adequate supply of municipal potable water for operation of the original project; (2) had considered water conservation in the design of the original project such that water requirements would be minimized by project features such as dry low-NOx combustors and dry cooling, and that use of municipal water would be minimized by recycling process water, stormwater, and air chiller condensate; (3) had demonstrated that the capacity of the municipal sewer system was adequate for sanitary wastewater discharge from the original project; and (4) had demonstrated that the water quality and marine resources of the Mystic River would not be negatively impacted, based on the measures to pretreat process water so that wastewater discharges would meet all federal and state water quality requirements to preclude discharge of pollutants such as grease and oil, and monitor the quality of wastewater. Therefore, in the 1994 Cabot Decision, the Siting Board found that the environmental impacts of the original project would be minimized with respect to water use and wastewater discharge. 2 DOMSB at 410-411.

In this proceeding, the Company stated that the updated project would use approximately 60,000 gallons per day ("gpd") of potable water from the City of Everett (Tr. 2, at 125).[44] The Company provided correspondence from the City of Everett which stated that the City of Everett water supply can support the updated project's use of municipal water (Exh. HO-E-22). The Company asserted that it was committed to the water conservation measures documented in the 1994 Cabot Decision, and that discharges of wastewater, sanitary wastewater, and process wastewater[45] are not substantially different from those detailed in the 1994 Cabot Decision (Exh. CPC-1, at 79). Further, the Company stated that it has filed a renewal application for the National Pollution Discharge Elimination System ("NPDES") permit that it initially received March 18, 1993 (Exh. HO-V-18, Att. 1). The Company indicated that it has not proposed any changes for the discharge limits for constituents of concern in the initial NPDES permit (Exh. CPC-1, at 81).

The Siting Board notes that the Company intends to use less potable water for the updated project due to the elimination of oil as a back-up fuel, and that CPC would be

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44 CPC stated that original project would have used approximately 60,000 gpd of potable water from the City of Everett when burning natural gas, and approximately 317,000 gpd when burning oil (Tr. 2, at 125).

45 The Company stated that the level of process wastewater discharge has been reduced from 50,400 to 36,300 gpd (Exh. CPC-1, at 79 and 81).

implementing the same water conservation measures as accepted in the 1994 Cabot Decision. With regard to wastewater, sanitary wastewater, and process water, the discharges will remain essentially the same as in the 1994 Cabot Decision.

Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to water use and wastewater discharge.

d. Land Use

In the 1994 Cabot Decision, the Siting Board found that the record demonstrated that the original project would be compatible with the industrial nature of the surrounding land use. In addition, the Siting Board found that the record demonstrated that the original project would be consistent with City of Everett zoning requirements, area-wide development goals and CZM program policies. Therefore, the Siting Board found that the environmental impacts of the original project would be minimized with respect to land use. 1994 Cabot Decision, 2 DOMSB at 412.

In this proceeding, the Company indicated that the updated project would be sited at the same industrial location as the original project (Exh. CPC-1, at 1).[46] The Company stated that the updated proposal would be consistent with existing land-uses, area-wide development goals, and CZM program policies, as well as with the City of Everett's zoning by-laws (Exh. CPC-1, at 79). The Company indicated that the reduction in stack height from 240 feet as originally proposed to 150 feet would eliminate the need for a zoning variance (id.; Tr. 2, at 124). In addition, the Company provided a list of changes made to the zoning by-law of City

46 In the original proceeding the Company indicated that the original project would be located within an industrially zoned district and that existing land use in the vicinity included the DOMAC Terminal, a commercial printing facility, a sand and gravel facility, a cement receiving and distribution center, a petroleum products distribution terminal and electric and natural gas utility facilities. 1994 Cabot Decision, 2 DOMSC at 411. The Company stated that the original project would be compatible with existing businesses and would be located at least 2,000 feet from residential neighborhoods. Id.

of Everett since the date of the 1994 Cabot Decision, and asserted that the updated project complies with the current by-law (Exh. HO-E-24).

The Siting Board notes that the updated project would remain compatible with the industrial nature of the area as well as continue to be consistent with zoning and land use requirements, goals and policies. Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to land use impacts.

e. Wetlands and Waterways

In the 1994 Cabot Decision, the Siting Board found that the record demonstrated that the original project would not impact wetland resources associated with the Mystic River and that impacts to the water quality and marine resources of the Mystic River would be minimized. The Siting Board therefore found that the environmental impacts of the original project would be minimized with respect to wetlands and waterways. 1994 Cabot Decision, 2 DOMSB at 413.

In the current proceeding, the Company stated that the design of the updated project does not change the project's impacts on wetlands or on the water quality of the Mystic River and marine resources, and that construction would not occur within the coastal wetland resource areas of the Mystic River (Exh. CPC-1, at 81). In addition, the Company stated that the site of the updated project falls outside of the riverfront protection resource area, as established in the 1996 Rivers Protection Act (Exh. HO-E-23).

The Siting Board notes that the design of the updated project ensures the avoidance of impacts to the wetlands and waterways in the vicinity of the updated project. Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to wetlands and waterways.

f. Safety

In the 1994 Cabot Decision, the Siting Board found that the record demonstrated that the design of the original project included safety features to: (1) avert spills of hazardous materials; (2) contain any accidental spills of hazardous materials; and (3) ensure that operation of the original project in close proximity to the LNG terminal would not present hazardous conditions. 2 DOMSB at 417. The Company also committed in the 1994 Cabot proceedings to implement all recommendations set forth in an independent safety assessment conducted for the City of Everett and to developing an Emergency Response Plan in conjunction with local authorities, similar to plans found acceptable by the Siting Board in previous reviews of generating facilities. See Altresco Lynn Decision, EFSB 91-102, at 204; 1993 BECo Decision, EFSB 90-12/90-12A at 137; Enron Decision, 23 DOMSC at 220.

In the 1994 Cabot Decision, the Siting Board also held that the record demonstrated that the Company was committed, consistent with state requirements, to take appropriate measures during construction to avoid potential hazards resulting from existing site contamination. The Siting Board noted that construction plans for the original project would incorporate measures to ensure that worker exposure to subsurface contaminants was avoided and movement of existing subsurface contaminants was minimized. Where removal of contaminated soils and groundwater would be required, protocols for excavation would be established prior to excavation to protect worker health and safety, and hazardous materials would be removed and disposed of in accordance with applicable regulations. In addition, site remediation and final engineering design would be monitored by the MDEP and a site-specific Health and Safety Plan would encompass all construction-related activities. The Siting Board therefore found that with implementation of the aforementioned mitigation measures, that the environmental impacts of the original project would be minimized with respect to safety. 1994 Cabot Decision, 2 DOMSB at 417-418.

In the current proceeding, the Company asserted that the impacts of construction on public safety would not be different from the original project, and that the impacts of operations of the updated project, including the split shaft design, would not present any additional risk to the health and safety of either the public or workers (Exh. HO-CPC-1, at 81; CPC Brief at 81).[47]

The Company provided information indicating that the storage and transportation of aqueous ammonia would be as described in the 1994 Cabot Decision (Exh. CPC-1, at 81). With regard to the storage and use of potentially hazardous substances, the Company indicated that it conducted an updated hazard assessment, which reflects the revised layout and split-shaft design, in order to comply with section 112(r) of the Clean Air Act (Exh. CPC-2, App. F). The hazard assessment evaluated the worst-case accidental release of aqueous ammonia (id.). The Company explained that the maximum predicated ammonia concentrations at the closest public use area are in the range of 22,200 to 30,560 ug/m^3, well within a limit of 140,000 ug/m^3, the guideline adopted by the American Industrial Hygiene Association (Exh. CPC-2(2A) at 6, 9). The results of the hazard assessment indicate that the distance to the nearest public receptor is greater than that to the point of maximum acceptable concentration for the worst-case accidental release (Exh. HO-E-31).

The Company stated that it has completed Phases I, II and III of the Massachusetts Contingency Plan ("MCP") process (Exhs. CPC-1, at 81; HO-E-34 (Att.1)).[48] CPC provided

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47 In the original proceeding, the Company stated that to ensure that the operation of the original project in close proximity to the LNG terminal would not present hazardous conditions, it would include the following safety features: (1) safe location and orientation of major equipment; (2) extensive fire protection systems; (3) barrier walls; (4) automatic fuel shut-off valves, and (4) automatic shut-down of the original project where concentrations of natural gas are detected at the property line. In addition, since fuel would be delivered via off-site pipelines, no storage for flammable fuels at the site would be required. 1994 Cabot Decision, 2 DOMSC at 415.

48 In the 1994 Cabot Decision, the Company indicated that an initial evaluation of the site, performed in accordance with Phase I of the MCP, confirmed the existence of hazardous substances within the site subsurface and groundwater. CPC noted that the MDEP had classified the site as a "non-priority disposal site" and had granted a waiver of approval requirements. Thus, the Company indicated the MDEP would monitor completion of the MCP process but that the Company would be allowed to proceed through the MCP process without MDEP approval of each phase. 1994 Cabot

(continued...)

documentation from a licensed site professional that the remediation methodologies presented in the existing record remain sufficient to protect worker and public safety in accordance with the MCP standards (Exh. HO-E-34 (Att.1)).[49] The Company added that, as stated in the 1994 Cabot Decision, all construction activities would be subject to a site specific Health and Safety Plan, consistent with state requirements (Exhs. CPC-1, at 81; HO-E-33).

The Company stated that it would adhere to all recommendations cited in the independent safety assessment conducted for the City of Everett, as discussed in the 1994 Cabot Decision (Tr. 2, at 104).[50] In addition, the Company indicated that it would prepare an emergency response plan, in collaboration with local authorities, which would include specifications for prevention practices and emergency contacts (Tr. 2, at 105).

The Siting Board notes that the design of the updated project would not incur additional health or safety risks to the public. Further, the safety measures specified in the 1994 Cabot Decision would be adhered to under the updated project. In addition, a new ammonia modeling analysis was conducted on the updated project, with the results indicating that the

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[48](...continued)
Decision, 2 DOMSB at 416-417.

[49] In the 1994 Cabot Decision, the Company stated that it would: (1) cap the entire site with clean fill to provide additional vertical separation between the new facility and subsurface contamination, and (2) use steel "H" piles for foundations to minimize movement of existing soils and alteration of groundwater paths. The Company maintained that protocol for the removal of all contaminated substances would be established prior to excavation to protect worker health and safety and that all contaminated substances would be disposed in accordance with applicable regulations. Further, the Company indicated that the existing warehouse contains asbestos floor tile which would be removed prior to the demolition of the structure in accordance with applicable regulations. 1994 Cabot Decision, 2 DOMSB at 416.

[50] The safety assessment recommendations included: (1) installation of pressure relief devices in the ammonia storage tanks; (2) installation of gas detectors along the perimeter of the original project; and (3) use of explosion-proof electrical equipment close to the boundary of the DOMAC Terminal. 1994 Cabot Decision, 2 DOMSB at 414, n. 207.

project would fall well within the guidelines adopted by the American Industrial Hygiene Association. Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to safety.

g. Traffic

In the 1994 Cabot Decision, the Siting Board found that the intersection that provided direct access to the original site operated at an unacceptable level of service ("LOS") (LOS F) during the morning and afternoon peak hours, and that delays at the intersection would increase during construction of the original project. However, the Company had proposed a number of mitigation measures that would restrict traffic to and from the site during peak hours and encourage use of alternative routes to the site. Therefore, in order to minimize traffic impacts during peak hours, the Siting Board required that CPC: (1) schedule the construction work shift to avoid arrivals and departures during the peak commuter hours of 7:30 a.m. to 8:30 a.m. and 4:30 p.m. to 5:30 p.m.; (2) schedule truck arrivals to be spread over the construction work shift; and (3) where possible, arrange for construction materials to be delivered by rail or barge. In addition, the Siting Board required that the Company, in consultation with the City of Everett, implement measures that would encourage the use of public transportation and alternative routes to the site by construction workers. The Siting Board found that with the implementation of these conditions, the environmental impacts of the original project would be minimized with respect to traffic impacts. 1994 Cabot Decision, 2 DOMSB at 419.

In the current proceeding, CPC asserted that the construction and operation of the updated project would not result in a significant impact to traffic in the vicinity of the updated project (Tr. 1, at 161; CPC Brief at 154-156). CPC stated that revised traffic analyses for the updated project indicate that the access intersection now operates at an acceptable LOS (LOS C) (Exh. CPC-1, at 82). However, the Company asserted that it would abide by the three conditions relative to traffic mitigation required by the Siting Board in the 1994 Cabot Decision (id.).

The Company's analysis demonstrated that the LOS would remain at level C under both 1999 construction conditions and 2000 operating conditions (id. at Tables J-6 and J-7). CPC explained that the difference between the 1990 LOS and the updated LOS is due to improved signal timing, poor estimation of the actual intersection delays in the original traffic study, and use of a more accurate LOS methodology in the updated study (Exh. HO-E-18; Tr. 1, at 159). The Company also provided information which now places the morning peak hour at 7:15 to 8:15 a.m. and the evening peak hour at 5:00 to 6:00 p.m. (Exh. CPC-1, App. J at 1).[51] In regard to parking for construction workers, CPC indicated that it is evaluating three off-site alternatives located in the IEIP, two properties owned by Boston Gas located west of the project site (one of which is presently leased by DOMAC), and a property owned by Exxon located north of the project site (Exh. HO-E-19; Tr. 1, at 164). Further, the Company indicated that DOMAC owns additional property close to the waterfront area which could be used for worker parking (Tr. 1, at 165).

The traffic analyses presented in the original proceeding identified an unacceptable LOS F at the access intersection of Rover Street and Route 99, which required a series of traffic mitigation conditions developed in the 1994 Cabot Decision to ensure minimum traffic impacts. Here, the Company has determined through an updated traffic analysis that the existing LOS is acceptable and will remain at that level during both construction and operation. The Siting Board notes that although the LOS at this intersection has been improved through signal changes, Route 99 remains a heavily traveled road, and the IEIP hosts a significant amount of truck traffic which serves to slow down the traffic flow. Therefore, it would be prudent to adhere to the original traffic mitigation conditions, as agreed to by the Company. Because the updated traffic study indicates that the peak morning hour is now 7:15 a.m. to

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[51] In the original petition the morning peak hour was shown to be between 7:30 to 8:30 a.m. and the evening peak hour was shown to be between 4:30 to 5:30 p.m. (Exh. CPC-1, App. J at 1).

8:15 a.m., Condition E is revised to require CPC to schedule the construction work shift to avoid arrivals and departures during the peak commuter hours of 7:15 a.m. to 8:15 a.m. and 5:00 p.m. to 6:00 p.m.

Accordingly, with implementation of the aforementioned mitigation measures, the Siting Board finds that the environmental impacts of the updated project will be minimized with respect to traffic.

h. Visual

In the 1994 Cabot Decision, the Siting Board found that the record demonstrated that the original project would be located within an industrial area, would be consistent in terms of size, scale and form with the existing structures in the area and would not alter the visual character of the area. The Siting Board therefore found that the environmental impacts of the original project would be minimized with respect to visual impacts. 1994 Cabot Decision, 2 DOMSB at 420.

In the current proceeding, the Company stated that the height of the updated exhaust stack would be reduced to 150 feet, lower than the 240 feet originally proposed (Exhs. CPC-1, at 3; HO-E-28, Att. 1). The Company presented a comparison of the dimensions of the major structures between those proposed for the original project and those proposed for the updated project (Exh. HO-E-28, Att. 1). The comparison indicated that the ground area of the air-cooled condenser would be 28,675 square feet, approximately 80 percent larger than in the original proposal (id.). With the exception of the exhaust stack, the highest project feature would still be below the City of Everett zoning limitation of 100 feet (id.; Exh. CPC-1, at 82).

The Siting Board notes that, as currently proposed, the exhaust stack will be 90 feet lower than in the original proposal. Further, the surrounding area remains predominantly industrial and includes expansive structures, such as LNG tanks and the Mystic generating station.

Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to visual impacts.

i. Electric and Magnetic Fields[52]

In the 1994 Cabot Decision, the Siting Board noted that the original project would be interconnected with the bulk transmission system via a 345 kV underground line approximately one-half mile in length. The Siting Board found that based on the record, there would be no electric fields and only minimal magnetic fields at ground level along the route of the interconnection line between the original project and the Mystic Substation.[53] The Siting Board therefore found that the environmental impacts of the original project would be minimized with respect to EMF. 1994 Cabot Decision, 2 DOMSB at 421.

In the current proceeding, the Company stated that it does not propose any changes to the design of the transmission line except for the use of a slightly larger diameter conductor (Exh. CPC-1, at 83; Tr. 1, at 83). With regard to the regional transmission system, the Company indicated that, because of its location in the local Boston import region of NEPOOL, the proposed facility would: (1) off-load some remote transmission, thereby deferring the need for upgrades to the system; (2) decrease system losses; and (3) improve voltage when load is supplied locally (Tr. 1, at 84-85).

The Siting Board notes that the design of the transmission line remains essentially the same as described in the original proceeding. Consequently, electric fields and magnetic fields

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52 Electric and magnetic fields produced by the presence of voltage and the flow of current are collectively known as electromagnetic fields or "EMF."

53 In the 1994 Cabot proceeding, the Company stated that electric fields would be shielded by the overlying fill material and that the transmission line would therefore not generate above-ground electric fields. 1994 Cabot Decision, 2 DOMSB at 421. Further, the Company stated that magnetic fields at ground level would be minimal because the transmission line would be installed within a steel pipe which would shield the magnetic fields. Id.

at ground level along the route of the interconnection would remain minimal. In past reviews, the Siting Board has held that, as part of pursuing interconnection plans that require upgrades to the regional transmission system, generating facility applicants also should work with transmission providers to seek inclusion of practical and cost-effective transmission designs to minimize magnetic field levels along affected ROWs. ANP Bellingham Decision, EFSB 97-1, at 157; Millennium Power Decision, EFSB 96-4, at 176; Silver City Decision, 3 DOMSB at 353-354. Given the updated project's location in the Boston import region, the project would off-load some regional transmission lines. Although the interconnection study is still pending, the Company does not expect the project to require more than minimal upgrades to the regional transmission system. Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the environmental impacts of the updated project would be minimized with respect to EMF.

j. Vibration

(1) Position of the Parties

(a) Arguments of Daniels

Daniels stated that its printing business is housed in two buildings, one which abuts the site proposed for the updated project ("Building 1"), and another which is directly across the street ("Building 2") (Daniels Brief at 1).[54,55] Daniels asserted that pre-construction, construction, and/or operation activities at the proposed site will create "excessive or

54 Daniels stated that it is the fourth largest financial printer in the United States, employing 380 people in its four locations (two locations in Massachusetts, one in New York, New York, and one in Washington D.C.) (Exh. DP-10, at 2). Three hundred forty-five of the employees work at the Everett location which is staffed 24 hours per day for five or seven days a week depending on the needs of its customers (id.). Daniels stated that sales in 1997 were in excess of $66,000,000 and forecasted that sales in 1998 will exceed $70,000,000 (id.).

55 Buildings 1 and 2 are located at 61 and 40 Commercial Street, respectively (Exh. DP-10 at 2).

intolerable ambient noise, vibration and dust levels that would adversely impact and cause irreparable harm to Daniels' business operations" (Daniels Brief at 1). Daniels stated that it is requesting the following relief from the Siting Board: (1) that the Siting Board approve CPC's updated petition only if and when engineering consultants have completed all noise, vibration and dust testing associated with the activities of both CPC and Daniels, and (2) in the alternative, that the Siting Board deny CPC's updated petition if engineering test results conclude that the demolition, pre-construction, construction and/or operational activities associated project would "impermissibly" impact the business activities of Daniels (id.). Daniels argued that pursuant to the authority given the Siting Board in G.L. c. 164, § 69J, enforceable conditions may be imposed by the Siting Board to prevent "irreparable harm" to the operations of Daniels from noise, vibration and dust (id. at 2).[56] Further, Daniels stated that it disagrees with the arguments of CPC that economic as opposed to environmental interests fall outside the scope of the Siting Board's review (Daniels Reply Brief at 3). Daniels also argued that vibration issues of all kinds should be considered noise impacts, since noise is the audible range of vibrations (id.).

With regard to the issue of impacts on its equipment, Daniels presented evidence that if its Heidelberg MV-30 press (the "Press") became misaligned, it would be inoperable, and due to the sensitive nature of the work, printing deadlines could be missed and it would be very difficult, if not impossible, to find vendors who could provide substitute service (Tr. 4, at 29 to 33). Daniels also asserted that differential displacement greater than 0.002 inches across the roller bearing of the Press "could result in problems" (Exh. HO-DP-5; Tr. 4, at 43; Daniels Brief at 8). In addition, Daniels presented a letter from the manufacturer of the Press stating that "that seismic vibrations and differential movements caused by the construction could affect both the alignment and the performance of the Press" (Exh. CAB 1-2, Att. 1). Further, the manufacturer stated that "[a]ny such misalignment might not be detected during printing, but could reduce the life of certain components. It is recommended that the [P]ress be

56 The Siting Board notes that this proceeding is being adjudicated pursuant to G. L. c. 164, § 69J and not the recently enacted G.L. c. 164, § 69J¼.

realigned...after the construction is completed" (id.). Evidence was also presented that, according to the manufacturer, there is no practical way to calculate the effect of the construction activities on operations of the Press without a testing program prior to construction (id.).

On cross examination, Daniels' witness, Mr. McKown, indicated that he was not certain whether CPC's construction activity would disrupt the Press or any of Daniels' other equipment or presses (Tr. 4, at 59-60). Also on cross examination, Daniels' witnesses, Mr. Kenny and Mr. McKown, confirmed that the manufacturer of the Press does not have established vibration specifications for the Press (Tr. 4, at 26, 60-61).

Daniels presented extensive evidence as to the level of vibrations that could result from construction activities, specifically pile driving (Exhs. CAB 1-8, Att. No. 1; DP-7, DP-8; Tr. 4, at 44-46, 53-55). Daniels' witness, Mr. McKown, testified that there are numerous obstructions and considerable debris at the proposed site and that hitting such obstructions during pile driving would result in higher than normal vibrations (Tr. 4, at 57-58; Daniels Brief at 4). In addition, Daniels argued that differential settlement as a result of pile driving could do damage to one of Daniels' buildings (Exh. DP-8; Tr. 3, at 84-96; Tr. 4, at 151-152, 164-165; Daniels Brief at 9).

Daniels stated that there are several mitigation measures that can be undertaken to significantly reduce or eliminate vibrations resulting from pile driving. Daniels asserted that, first, a test program should be implemented whereby test piles would be driven to measure vibrations and the resulting impacts to Daniels' equipment (Exhs. DP-11, at 5-6; HO-DP-1; Tr. 4, at 59; Daniels Brief at 11-12). Further, Daniels recommended that geotechnical borings at the site of the proposed project and at the site of both of Daniels' buildings be immediately undertaken to examine the subsurface conditions of these three parcels of lands (Daniels Brief at 12). Finally, Daniels asserted that the updated project could be constructed without driving piles and recommended use of alternative support mechanisms such as drilled shafts, minipiles, or other forms of deep foundational support (Tr. 4, at 58; Daniels Brief at 11).

(b) Arguments of CPC

CPC asserted that potential vibration impacts of projects have not traditionally been among the environmental impacts reviewed by Siting Board and that adverse economic impacts, if any, are more properly addressed in Courts and not before the Siting Board (CPC Brief at 6). In support, CPC argued that the Siting Board's mandate to ensure a necessary energy supply with a minimal impact on the environment at the lowest possible cost does not mean that the Siting Board is also mandated to prevent economic harm from environmental impacts such as noise, vibrations and dust (CPC Reply Brief at 1, 2). Relative to the relief sought by Daniels, CPC argued that the Siting Board does not and should not require the collection of project-specific empirical evidence for every possible environmental impact before it approves an application to construct a generating facility and that such a policy would be impractical and unnecessary (CPC Reply Brief at 19). Moreover, CPC contends that it has shown that the updated project is needed, least cost and viable, and that its impacts would be minimized consistent with the Siting Board's mandate in G.L, c. 164, § 69H (id. at 20).

CPC also argued that, to the extent that the Siting Board does take cognizance of the issue of vibration, CPC's estimates of vibration impacts at the Daniels' site from pile driving demonstrate that pile driving will not cause adverse impacts on Daniels' equipment (CPC Brief at 89).[57]

CPC stated that it was willing to undertake "intelligence gathering" before beginning pile driving to determine the most effective locations on the updated project site that would accommodate the project's structures while minimizing vibrations (Tr. 4, at 130;

57 Evidence was presented by both parties indicating that the closest pile driving to the Press would be between 150 to 180 feet (Exh. DP-1, Att 1, at 3; Tr. 3, at 110; Tr. 4, at 66; Cabot Brief at 91, n.63). CPC estimated that peak vibration, based on pile driving in clay with a drop hammer producing 35,000 foot-pounds of energy, would be 0.04 inches per second, at a distance of 180 feet (Exh. DP-1). Daniels estimated that the maximum vibration, assuming pile driving in sand with hammers producing up to 50,000 foot-pounds of energy, would be eight times greater, at a distance of 150 feet, than that estimated by the CPC, above (Daniels Brief at 8).

CPC Brief at 106). Specifically, this process would involve data collection to learn more about the presence of any potential obstructions in the soil on the updated project site (CPC Brief at 106). CPC also stated that to the extent that significant obstructions are identified, CPC could pre-auger those obstructions to eliminate them from the path of the pile, or move the pile to avoid the obstruction (Tr. 4, at 130; CPC Brief at 106). CPC also stated that it would then monitor all construction-related vibrations at the project site and at Daniels' Building 1 to confirm that vibrations from the updated project remain below state blasting limits (CPC Brief at 106).[58]

(2) Analysis and Findings

The record shows that construction of the proposed facilities will involve pile driving, possible augering, removal of debris and waste, and noise. CPC and Daniels each have presented evidence and argument as to whether vibrations caused by pile driving would have any impact on the Daniels' Press, and as to whether such impacts fall within the Siting Board's jurisdiction.[59] Before addressing the evidence regarding the impacts of vibrations caused by pile driving, the Siting Board first considers whether it has jurisdiction under G.L. c. 164, § 69J to consider the issue of vibration impacts as it is raised by Daniels in this proceeding.

Daniels has argued that CPC's petition should be denied if it is shown that construction or operation of the proposed project "would impermissibly impact the business activities of Daniels". The Siting Board notes that this argument reflects a fundamental misunderstanding of the Siting Board's mandate. Pursuant to G.L. c. 164, § 69H, the Siting Board is charged with ensuring "a necessary energy supply for the Commonwealth with a minimum impact on

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58 Although the State Blasting Regulations of the Massachusetts State Fire Code are not directly applicable, CPC stated that during pile driving it will voluntarily undertake not to exceed the vibration threshold for blasting under 527 C.M.R. § 13.09 (Tr. 3, at 139-143; CPC Brief at 87).

59 Although Daniels initially raised concerns regarding adverse impacts on several pieces of its equipment, the only piece addressed with any specificity during the proceeding was the Press.

the environment at the lowest possible cost". G.L. c. 164, § 69J sets forth a number of categories of environmental impacts which the Siting Board is required to investigate, including land use impacts, water resource impacts, air quality impacts, solid waste impacts, noise impacts, and radiation impacts. The Siting Board reviews these impacts in order to determine whether the overall environmental impacts and costs of a proposed facility have in fact been minimized. If the environmental impacts and costs of a necessary facility have, on balance, been minimized, the Siting Board is obligated to approve the facility; its statute does not provide for rejection of a facility simply because there may be some remaining impact to specific individuals or companies. The Siting Board recognizes that environmental impacts may well have economic consequences; however, the Siting Board's mandate is to minimize the impacts, not to quantify the consequences to each affected individual and company and determine whether any is "impermissible".[60] Similarly, any condition imposed on a proposed facility should relate to minimizing the environmental impacts or costs of the facility within the statutory framework.

Daniels notes that the Siting Board has jurisdiction over noise impacts, which it argues should be construed as including vibration impacts of all kinds. The Siting Board recognizes that noise is a manifestation of vibrations in a particular range of frequencies. "Noise can have many adverse effects, including damage to hearing, disruption of normal activity, and general annoyance. Extremely loud noise, such as a sonic boom, can also cause physical damage to structures." Environmental Law (2d Edition), Matthew Bender, §6.01. In the past, the Siting Board has reviewed the impacts of audible noise (i.e., noise which is within the range of human hearing and can be measured in decibels by receptors placed in various locations away from the noise source). ANP Bellingham Decision, EFSB 97-1, at 130-144; Millennium Power Decision, EFSB 96-4, at 141-158; NEA Decision, 16 DOMSC at 401-403. While the

60 The Siting Board notes that certain steps taken to minimize the overall environmental impacts of a facility (e.g., moving an access road away from a wetland area or orienting a facility to minimize overall noise impacts) could increase impacts on an individual abutter (e.g., by moving the access road or facility closer to the abutter's property).

Siting Board acknowledges that all noise is propagated by vibrations, it disagrees with Daniels' proposition that all vibrations must therefore be considered noise.[61] In the absence of a compelling argument otherwise, the Siting Board holds that it is inappropriate to stretch the common meaning of the term "noise" to include the inaudible impacts of vibrations caused by pile driving.

The Siting Board has in the past reviewed the effects of vibration on abutting land uses in the context of blasting and its potential to affect wells. 1990 Berkshire Decision, 20 DOMSB at 109, 189-190. We note that, in that context, the potential impact from vibrations was a water resource impact affecting a number of neighboring property owners, which clearly fell under the Siting Board's jurisdiction. It is also possible that construction operations such as pile driving could raise issues regarding solid waste, land use, or some other type of environmental impact. Here, however, Daniels has raised the issue of vibrations as it relates to a single private, economic interest -- the operation of an abutting industrial concern -- without offering an explanation of how that interest bears on the question of whether the environmental impacts and costs of the proposed facility have been minimized. The Siting Board therefore concludes that the impacts to Daniels' Press of vibrations caused by pile driving, and particularly the question of whether Daniel's business activities would be irreparably harmed by such impact, are not a proper subject for Siting Board review in this proceeding.

The Siting Board also notes that, even if it did take up this issue, it would consider the evidence in light of its statutory mandate to provide for a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The record indicates that CPC has committed to a series of mitigation measures including detailed

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61 The Siting Board notes from its review of Environmental Law, supra., that the concept of noise has been expanded in some venues to include broader impacts of so-called *structure-borne* or *impact noise* (e.g., the New York City Building Code, Environmental Law at §6.03)). However, the Siting Board has not construed its mandate this broadly and declines to do so in this case, particularly in the absence of express statutory language.

pre-planning of pile driving activity; pre-augering or relocation of piles as needed based on identifications of obstructions prior to or during pile driving; voluntary adherance to vibration regulations applicable to blasting; and monitoring of all construction-related vibrations. In addition, CPC has indicated that projects of this nature typically require pile driving or similar activities to create support for heavy pieces of equipment. Daniels has claimed that the pile driving required for this project nonetheless will cause damage to its highly sensitive Press. CPC and Daniels each have presented extensive evidence in this proceeding regarding the level of vibrations likely to result from the use of various types and sizes of pile drivers and piles, driven to various depths through various types of soil. However, neither Daniels nor CPC could document a threshold level of vibrations which would require realignment or otherwise damage the Press, and the record indicates that the manufacturer of the Press does not have an established standard for vibrations. Therefore, the record does not support a finding that vibrations caused by pile driving associated with the CPC project are likely to cause harm to the Press or its operations.

Consequently, if the Siting Board had taken up this issue, it would have found, based on the information and data in the record, that, with the implementation of the mitigation measures to which CPC has committed in this proceeding, the impacts of vibrations caused by pile driving would be minimized consistent with minimizing cost. The Siting Board would not have conditioned its approval on the implementation of vibration mitigation beyond that to which CPC has committed in this proceeding.

Nothing in this analysis is intended to relieve any party from liability in any future litigation that might result from CPC's pile driving activities. If damage to the Press does ultimately ensue from CPC's construction work, the parties would still have recourse to their traditional legal remedies including but not limited to possible claims on insurance, construction bonds, or determination by a Court of competent jurisdiction.

The Siting Board does wish to note the substantial efforts on the part of both Daniels and CPC to develop the record and to search for compromise in this matter. Daniels and CPC have made substantial progress towards developing a common approach to the mitigation of vibration impacts. The Siting Board anticipates that CPC will fully implement the mitigation measures to which it has committed in this proceeding, and urges CPC to continue to work with Daniels to minimize any possible harm to Daniels' equipment.

3. Conclusion

The Siting Board finds that the Company has provided sufficient information on the environmental impacts of the updated project, including mitigation measures and project design, for the Siting Board to determine whether the environmental impacts of the updated project would be minimized.

The Siting Board has found that, based on the above mitigation measures, conditions, and project design, the environmental impacts of the updated project would be minimized with respect to air quality, noise, water use and wastewater, land use, wetlands and waterways, safety, traffic, visual impacts, and EMF.

C. Cost Analysis of the Updated Project

In this section, the Siting Board evaluates whether the Company has provided sufficient information on the costs of the updated project to allow the Siting Board to determine if an appropriate balance would be achieved between environmental impacts and cost.

In the 1994 Cabot Decision the Siting Board found that the Company had provided estimates of the overall costs of the original project and had specified cost advantages due to unique technological and siting aspects of the original project. The Siting Board therefore found that the Company had provided sufficient information on the costs of the original project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs. 1994 Cabot Decision, 2 DOMSB at 424.

In the current proceeding, CPC provided a construction cost estimate of $221 million or $631/kW in 1997 dollars, and $689/kW in 2000 dollars (Exh. CPC-1, at 26, 73). CPC provided an itemized breakdown of these costs, including estimates of development costs, contingency funds, off-site project costs, start-up costs, and interest payments (id. at Table IV.C-1).

The Company maintained that the cost advantages of the updated project cited in the original review, relating to site and technological advantages, and to DOMAC's use of thermal energy from the updated project, are still applicable (see 2 DOMSB at 422-423; Tr. 1, at 139). The Company asserted that the updated project is substantially more efficient that the original project (Exh. CPC-1, at 26). Further, the Company indicated that the capital cost of the updated project would still compare favorably to the capital cost of a generic, advanced gas turbine combined-cycle facility (Tr. 1, at 144).

Accordingly, the Siting Board affirms the finding made in the 1994 Cabot Decision that the Company has provided sufficient information on the costs of the updated project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

D. Conclusions on the Updated Project

In this section, the Siting Board reviews the consistency of the updated project with its overall review standard, which requires that an appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as between these environmental impacts and cost.

The Siting Board has found that, with the implementation of the conditions specified in Sections III.B.2.a, III.B.2.b, and III.B.2.g above, the environmental impacts of the updated project would be minimized with respect to air quality, water supply and wastewater, wetlands and waterways, noise, land use, visual impacts, traffic, safety, and EMF. Further, in Section III.B.3, the Siting Board has found that CPC provided sufficient information on the costs of the updated project to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and costs.

The record indicates that there are no significant issues involving the balance among air quality, noise, water use and wastewater, land use, wetlands and waterways, safety, traffic, visual impacts, and EMF, nor between any of these concerns and cost. Consequently, there is no need for further analysis of the balance among conflicting environmental impacts or between environmental impacts and costs.

Therefore, the Siting Board finds that, with the implementation of the conditions set forth in Sections III.B.2.a, III.B.2.b, and III.B.2.g above, (1) the environmental impacts of the updated project would be minimized, and (2) an appropriate balance would be achieved among conflicting environmental concerns as well as between environmental impacts and costs.

IV. DECISION

The Siting Board's enabling statute directs the Siting Board to implement the energy policies contained in G.L. c. 164, §§ 69H to 69Q, to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H. In addition, the statute requires the Siting Board to determine whether plans for expansion or construction of energy facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the Commonwealth. G.L. c. 164, § 69J.

In Section II.A.3 above, the Siting Board found that the Company has established need for the updated project. Further, in Section II.B. 4, the Siting Board found that, upon compliance with the listed conditions, CPC will have established that the updated project is reasonably likely to be a viable source of energy.

In Section III.B.4 above, the Siting Board has found that with implementation of the listed conditions relative to noise, traffic and CO_2 offsets, the environmental impacts from the updated project would be minimized.

Further, in the 1994 Cabot Decision and in Section III.B, above, the Siting Board has reviewed various environmental impacts of the proposed facility in light of related regulatory or other programs of the Commonwealth, including programs related to air quality, noise, wastewater discharges, riverfront protection, control of pre-existing site contaminants, and coastal zone management. As evidenced by these analyses, the proposed facility will be consistent with identified requirements under all such programs. The Siting Board therefore finds that the proposed project is likely to be consistent with various health, environmental protection and resource use and development policies of the Commonwealth which relate to the environmental impacts and cost of the Commonwealth's energy supply.

Accordingly, the Siting Board finds that, upon compliance with the conditions set forth in Sections II.B and III.B, above, and listed below, the construction and operation of the updated project and ancillary facilities will be consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Board APPROVES the petition of Cabot Power Corporation to construct a 350 MW bulk generating project and ancillary facilities in Everett, Massachusetts subject to the following conditions.

(A) In order to ensure that the project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives, the Siting Board directs CPC to provide a copy of a signed EPC contract between CPC and Westinghouse or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

(B) In order to ensure that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, the Siting Board directs CPC to provide a copy of a signed O&M contract between CPC and Westinghouse OSC or a comparable entity that contains provisions that would provide reasonable assurance that the project would perform as a low-cost, clean power producer.

At such time as the Company provides the Siting Board with the information listed above, the Siting Board shall review the information and determine if the Company has complied with these conditions. The Company will not receive final approval of the updated project until it complies with these conditions.

In addition, the Company shall comply with the following conditions during construction and operation of the updated project.

(C) In order to mitigate CO_2 emissions, the Siting Board requires CPC to provide CO_2 offsets through a total contribution of $398,185, to be paid in five annual installments during the first five years of project operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff. If the Company chooses to provide the entire donation by the end of the first year of project operation, the CO_2 offset requirement would be a total contribution in the amount of

\$330,215, to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff.

(D) In order for impacts to community noise levels to be minimized, CPC shall: (1) incorporate all updated mitigation as described in Section III.B.2.b, above, so that the continuous noise increase from the operation of the updated project is no more than four decibels at any residence; (2) refrain from conducting construction that generates significant noise before 8:00 a.m.; and (3) confine all primary construction activity to between the hours of 6:30 a.m. and 5:30 p.m., Monday through Saturday, except as necessary for structural integrity or safety reasons.

(E) In order to minimize traffic impacts during peak hours, CPC shall: (1) schedule the construction work shift to avoid arrivals and departures during the peak commuter hours of 7:15 a.m. to 8:15 a.m. and 5:00 p.m. to 6:00 p.m.; (2) schedule truck arrivals to be spread over the construction work shift; (3) where possible, arrange for construction materials to be delivered by rail or barge; and (4) in consultation with the City of Everett, implement measures that would encourage the use of public transportation and alternative routes to the site by construction workers.

The conditions listed above supersede and replace Conditions A through F set forth in the 1994 Cabot Decision.

Because issues addressed in this decision relative to this project are subject to change over time, construction of the updated generating project and ancillary facilities must be commenced within three years of the date of this decision.

In addition, the Siting Board notes that the findings in this decision are based upon the record in this case. A project proponent has an absolute obligation to construct and operate its project in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the updated project to enable the Siting Board to make these determinations.

Peter M. Palica
Hearing Officer

Dated this 9th day of October, 1998.

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of October 8, 1998 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Janet Gail Besser (Chair, EFSB/DTE); James Connelly (Commissioner, DTE); W. Robert Keating (Commissioner, DTE); and David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development).

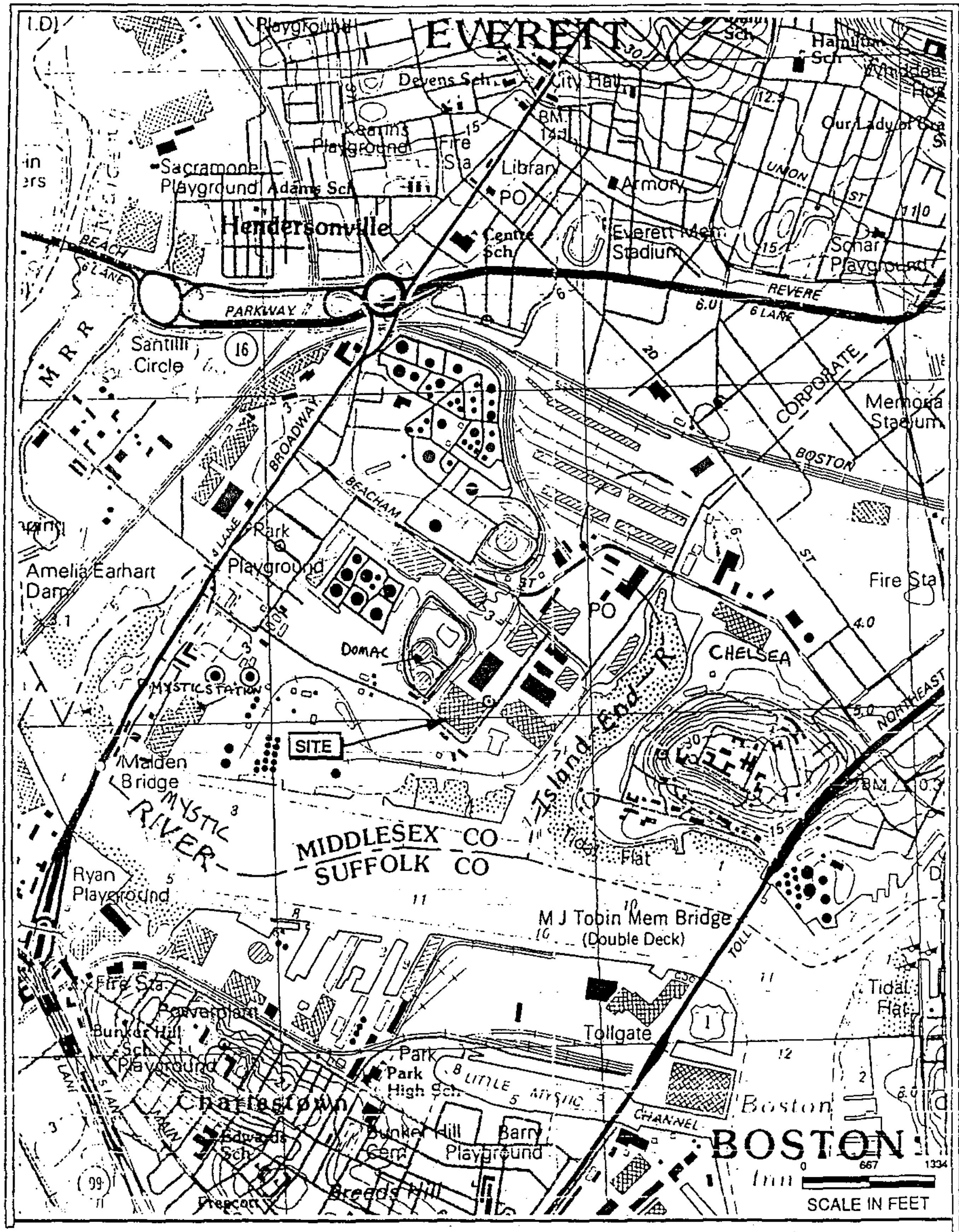
Janet Gail Besser

Janet Gail Besser
Chair

Dated this 9th day of October, 1998.

FIGURE I

SITE VICINITY MAP



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

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of New England Power Company for Approval to Construct Two 115 kV Underground Electric Transmission Cables and Associated Equipment in Boston and Quincy, Massachusetts	)	
The Petition of New England Power Company for a Determination that the Two Proposed Electric Transmission Cables in the Cities of Boston and Quincy are Necessary and Will Serve the Public Convenience and be Consistent with the Public Interest	)	EFSB 97-3
The Petition of New England Power Company for Exemption of Proposed Electric Substation Improvements from the Zoning By-Laws of the City of Quincy	)	

FINAL DECISION

Jolette A. Westbrook
Hearing Officer
October 9, 1998

On the Decision:
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Dana G. Reed

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Interested Person

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

Abbreviation	Explanation
BECo	Boston Edison Company
BVW	Bordering vegetated wetland
C&LM	Conservation and Load Management
Company	New England Power Company
Company Brief	New England Power Company's brief
Court	Supreme Judicial Court
CTG	Combustion turbine generation
Department	Department of Telecommunications and Energy
Dorchester Bay	Dorchester Bay Economic Development Corporation
DPW	Department of Public Works
DSM	Demand Side Management
EIR	Environmental Impact Report
EMF	Electric and magnetic fields
HDD	Horizontal directional drilling
kV	Kilovolt
L_{90}	The level of noise that is exceeded 90 percent of the time
MBTA	Massachusetts Bay Transportation Authority
MDC	Metropolitan District Commission
MDEP	Massachusetts Department of Environmental Protection
MECo	Massachusetts Electric Company
MEPA	Massachusetts Environmental Policy Act
mG	Milligauss
MGIS	Massachusetts Geographic Information Systems
MHC	Massachusetts Historical Commission
MHD	Massachusetts Highway Department
MNHESP	Massachusetts Natural Heritage and Endangered Species Program

MVA	Megavoltamperes
MW	Megawatt
NEES	New England Electric System
NEPCo	New England Power Company
Neponset River ACEC	Neponset River Area of Critical Environmental Concern
NEPOOL	New England Power Pool
NEPSCo	New England Power Service Company
Quincy	City of Quincy
ROW	Right-of-way
RPA	Rivers Protection Act
Siting Board	Energy Facilities Siting Board
Siting Council	Energy Facilities Siting Council

The Energy Facilities Siting Board hereby APPROVES the petition of New England Power Company to construct two 115 kV underground electric transmission cables in the cities of Boston and Quincy, Massachusetts using the Company's primary route.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

New England Power Company ("NEPCo" or "Company") is the wholesale generation and transmission subsidiary of New England Electric System ("NEES"), a public utility holding company (Company Brief at 1).

NEPCo has proposed to construct two 3.3-mile long, 115-kilovolt ("kV") underground transmission lines between the Boston Edison Company's ("BECo") existing Dewar Street substation in the Dorchester section of Boston and NEPCo's existing North Quincy substation on Spruce Street in Quincy (NEP-1, at 3-8, 3-12). The proposed project would establish an independent source of electric supply for the City of Quincy ("Quincy") (id.). NEPCo stated that Quincy is the primary commercial and industrial center in the South Shore area of Massachusetts Bay with approximately 40,000 customers (id. at 2-1). Quincy is an electrically isolated area and is presently supplied by NEPCo via two underground transmission lines located adjacent to each other in the city streets (id. at 1-1). NEPCo represents that these lines are vulnerable to a possible common mode failure that could interrupt the entire Quincy electrical supply for several days (id. at 2-6 to 2-10).[1]

For its primary route, NEPCo has proposed that the underground transmission lines generally follow the Southeast Expressway from BECo's Dewar Street substation in Boston to Victory Road (Exh. NEP-1, at 1-1, 1-3, Fig. 1-1). From Victory Road, the route would extend under the Neponset River to Quincy, then cross land owned by the Metropolitan District Commission ("MDC") and travel to Commander Shea Boulevard (id.). From there, the transmission lines would travel south along Commander Shea Boulevard and then under

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1 Common mode failure refers to a single event on the system which results in the outage of more than one supply system component. (For a more detailed discussion of common mode failure, see Section II.A.3a, below).

Hancock Street and would pass under the tracks of the Massachusetts Bay Transportation Authority ("MBTA") to NEPCo's North Quincy substation (id.).

NEPCo also has identified an alternative route for the proposed transmission lines. NEPCo indicated that the alternative route is identical to the primary route from the Dewar Street substation to Victory Road, but that from Victory Road south, the route would follow the Southeast Expressway to Conley Street, then proceed west on Conley Street to Tenean Street (id. at 3-35 to 3-36). From there, the route would travel south on Tenean Street, then west, crossing the MBTA tracks to Norwood Street (id. at 3-36). The route would then continue south on Norwood Street to MDC land bordering Morrissey Boulevard, travel west across the Boulevard, then south along the median strip through Neponset Circle to the bridge abutment (id.). The alternate route would cross the Neponset River along the bridge structure (id.). The route would then proceed down the exit ramp to Hancock Street in Quincy, along Hancock Street and across a private right-of-way to the North Quincy substation (id. at 3-37). A map of the NEPCo's primary and alternative routes is included as Figure 1.

B. Procedural History

NEPCo filed its Occasional Supplement to the Long Range Forecast ("petition") with the Siting Board on August 19, 1997 for approval to construct two 115 kV underground transmission cables and associated equipment as described herein. This petition was docketed as EFSB 97-3. On December 10 and 11, 1997, the Siting Board conducted public hearings on the petition in the City of Boston and the City of Quincy, respectively. In accordance with the direction of the Hearing Officer, NEPCo provided notice of the public hearing and adjudication.

Timely petitions to intervene were submitted by: Charles R. Tevnan; the Massachusetts Highway Department ("MHD"); and the MBTA. In addition, a late-filed petition to participate as an interested person was filed by the Dorchester Bay Economic Development Corporation ("Dorchester Bay").

The Hearing Officer allowed the petitions to intervene of the MHD and the MBTA. The Hearing Officer denied the petition of Mr. Tevnan to intervene but allowed him to participate as an interested person (Hearing Officer Procedural Order, January 26, 1998). The Hearing Officer also allowed the petition of Dorchester Bay to participate as an interested person (Hearing Officer Oral Ruling, March 19, 1998).

The Siting Board conducted evidentiary hearings on March 23 and March 24, 1998. NEPCo presented ten witnesses: Frank S. Smith, a consulting engineer for New England Power Service Company ("NEPSCo"), who testified regarding several project issues including need and site selection; Sharad Y. Shastry, a retail planning engineer with NEPSCo, who testified regarding transmission issues; Gabriel Gabremicael, an engineer, who testified regarding distribution issues; Gordon W. Whitten, a cable engineer with NEPCo, who testified regarding noise issues; Jonathan B. Lowell, manager of portfolio planning with NEPSCo, who testified regarding forecast issues; F. Paul Richards, senior program director in the environmental sciences and planning group for Earth Tech, who testified regarding environmental siting issues; Steven J. Pericola, an engineer in the substation engineering department at NEPSCo, who testified regarding environmental issues; John M. Zicko, lead engineer in the electrical engineering department at Boston Edison Company, who testified regarding construction impact issues; Daniel McIntyre, engineer at NEES, who testified regarding construction impact issues; and Dr. Peter A. Valberg, a consultant with Cambridge Environmental and facility member of the Harvard School of Public Health, who testified regarding electric and magnetic fields ("EMF") and their potential health effects.

The Hearing Officer entered 182 exhibits into the record, consisting primarily of NEPCo's responses to information and record requests. NEPCo entered one exhibit into the record.[2] NEPCo filed its brief on April 16, 1998 and Charles Tevnan filed a reply brief on April 27, 1998.

C. Jurisdiction

The Company's petition is filed in accordance with G.L. c. 164, § 69H, which requires

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[2] Absent objection, Mr. Tevnan and Dorchester Bay were permitted to enter into evidence written remarks they had prepared for this proceeding.

the Siting Board "to implement the energy policies ... to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," and pursuant to G.L. c. 164, § 69J, which requires electric companies to obtain Siting Board approval for construction of proposed facilities at a proposed site before a construction permit may be issued by another state agency.

The Company's proposal to construct two 3.5-mile long 115 kV electric transmission lines falls squarely within the second definition of "facility" set forth in G.L. c. 164, § 69G.[3] That section states, in part, that a facility is:

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

On October 28, 1997, NEPCo filed two petitions with the Department of Telecommunications and Energy (formerly the Department of Public Utilities) ("Department"): (1) requesting a determination of public convenience and necessity relative to the two proposed underground transmission cables; and (2) requesting a zoning exemption for proposed improvements at the North Quincy substation. These cases were docketed as D.P.U. 97-98 and D.P.U. 97-99, respectively. Although the Department has initial jurisdiction over such petitions, G.L. c. 164, § 69H(2) provides that the Siting Board may accept such matters for review and approval or rejection that are referred by the Chairman of the Department pursuant to G.L. c. 25, § 4, provided that it shall apply Department and Siting Board precedent in a consistent manner. The Chairman referred these two petitions to the Siting Board on November 17, 1997 in an Order in which these matters were consolidated with the Siting Board docket in EFSB 97-3. The Siting Board hereby accepts for review these two petitions.

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3 NEPCo's petition was filed with the Siting Board on August 19, 1997. Therefore, the statutes referenced in this proceeding are those that were in effect prior to the enactment of the Electric Restructuring Act, St. 1997, c. 164.

D. Scope of Review

In accordance with G.L. c. 164, § 69H, before approving an application to construct facilities, the Siting Board requires applicants to justify facility proposals in three phases. First, the Siting Board requires the applicant to show that additional energy resources are needed (see Section II.A, below). Next, the Siting Board requires the applicant to establish that its project is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the previously identified need (see Section II.B, below). Finally, the Siting Board requires the applicant to show that its site selection process has not overlooked or eliminated clearly superior sites, and that the proposed site for the facility is superior to a noticed alternative site in terms of cost, environmental impact, and reliability of supply (see Section III, below).[4] Additionally, in the case of an electric company which is required by G.L. c. 164, § 69I to file a long-range forecast with the Department, the applicant must show that the facility is consistent with the electric company's most recently approved long-range forecast. G.L. c. 164, § 69J. NEPCo is an electric company required to make such a filing and to make such a showing.[5]

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4 When a transmission line facility proposal is submitted to the Siting Board, the petitioner is required to present: (1) its preferred facility site and/or route; and (2) at least one alternative facility site and/or route. These sites and routes are described as 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 such a facility case, the Siting Board can approve a petitioner's preferred site or route, approve an alternative site or route, or reject all sites and routes. The Siting Board, however, may not approve any site, route, or portion of a route which was not included in the notice of adjudication published for the purposes of the proceeding.

5 To satisfy this requirement, NEPCo relies on the most recently approved Department forecast filed by Massachusetts Electric Company ("MECo"), NEPCo's affiliate. (For a detailed discussion of this issue see Section II.A.3.d, below.)

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, § 69H, the Siting Board is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Board evaluates whether there is a need for additional energy resources[6] to meet reliability, economic efficiency, or environmental objectives. The Siting Board must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

2. Description of the Existing System

The Company stated that the City of Quincy is part of its South Shore Power Supply Area ("South Shore PSA"), and that the Quincy area load constitutes approximately 60 percent of the entire South Shore PSA load (Exh. HO-N-15c).[7] The Company stated that Quincy is an electrically isolated area of significant load supplied by two underground 115-kV transmission lines from the BECo Edgar Station in Weymouth (Exhs. NEP-1, at 2-1, 2-3; HO-N-10). The Company explained that the transmission lines supply Quincy's two major substations -- Field

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

7 The Company indicated that Quincy is the second largest city served by NEPCo's retail distribution affiliate, MECo (Exh. NEP-1, at 2-1). The Company stated that there are approximately 40,000 customers (90,000 residents) in the City of Quincy (id.). The Company explained that Quincy is the primary commercial and industrial center in the South Shore area, and that Quincy customers include State Street Bank South, Marina Bay, Crown Colony Office Park, the Quincy shipyard, South Shore Hospital, and the MBTA (id.).

Street and North Quincy (id.). The Company stated that both pipe-type and self-contained underground lines are used along the existing supply route (Exh. NEP-1, at 2-1, 2-3).[8] The Company indicated that two pipe-type cables, designated 532S and 533S, extend for 2.1 miles from BECo's Edgar Station in Weymouth to NEPCo's Field Street substation in Quincy, which supplies 60 percent of the Quincy load (Exhs. NEP-1, at 2-1, 2-3; HO-N-3a).[9] The Company stated that two self-contained cables, designated 532N and 533N, extend for 3.3 miles from the Field Street substation to the North Quincy substation, which supplies the remaining 40 percent of the Quincy load via two 115/13.8 kV transformers (Exhs. NEP-1, at 2-1, 2-3; HO-N-3a).[10]

The Company indicated that there presently are no additional transmission voltage power sources or lines within Quincy (Exh. HO-RR-1, Att. 1; Tr. 1, at 23). The Company further indicated that no transmission links presently exist throughout the greater Quincy area to provide an interconnection between the northern and southern portions of BECo's area transmission system (Exhs. NEP-1, at 2-22 to 2-23; HO-RR-1, Att. 1).

3. Reliability of Supply

The Company asserted that the proposed project is needed in order to increase the reliability of the supply of electricity to the City of Quincy (Exh. NEP-1, at 2-11). The

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8 The Siting Board notes that throughout the record in this proceeding, the terms "line(s)" and "cable(s)" are used interchangeably.

9 The Company explained that residential, commercial, and industrial customers in east and south Quincy are supplied via 21 13.8 kV distribution feeders emanating from the Field Street substation (Exh. NEP-1, at 2-1). In addition, the Company stated that three 23 kV supply cables extend from the Field Street substation to the West Quincy distribution substation from where eight distribution feeders serve West Quincy customers (id.).

10 The Company explained that the North Quincy substation transformers serve the Atlantic and Wollaston substations and residential, commercial, and industrial customers in the North Quincy area via eight distribution feeders (Exh. NEP-1, at 2-1). The Company added that four distribution feeders from the Atlantic substation and eight distribution feeders from the Wollaston substation also serve customers in the North Quincy area (id.).

Company identified two problems with the present supply to the Field Street and North Quincy substations such that the existing supply configuration does not meet the reliability criteria of the Company (id. at 2-4, 2-6, Appendix C). First, the Company stated that the limited separation of the two existing underground cables, both from each other and from the surface of the pavement, make them vulnerable to simultaneous outage as the result of a single incident, termed a common mode failure (id. at 2-6 to 2-8). Second, the Company stated that the service restoration time for a repair of either the existing pipe-type or self-contained underground cables would exceed 24 hours (id. at 2-8). The Company maintained that, given the size of the Quincy load and the expected duration of a common mode failure, the adverse impacts of such a failure to the City of Quincy would be unacceptable (id. at 2-9 to 2-10).

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

a. Reliability Criteria

NEPCo indicated that a number of its service reliability and system design criteria are applicable to the classes of transmission and distribution found in the proposed project area (Exh. NEP-1, at 2-4, Appendix C). Although the Company's outage criteria focus largely on single contingency outages, they also address common-mode outage contingencies where a single event on the system causes two or more elements to experience an outage at the same time (id. at 2.6, Appendix C, Secs. 2.0 to 2.5.2, 2.5.4).[11] The possibility of a common-mode outage underlies the concerns about electric reliability in Quincy (id. at 2-6, Appendix C, Sec. 2.5.4).

The Company indicated that its common-mode outage criteria provide that "no load should be interrupted for more than 24 hours" (id., Sec. 2.5.4). The Company added that where a common mode outage would exceed 24 hours, its planning guidelines provide for mitigation measures if the affected facilities are identified as vulnerable to such a failure, and if the consequences of such a failure would be unacceptable (Exh. NEP-1, at 2-6).

The Siting Board has previously found that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain system reliability. Boston Edison Company Decision, EFSB 96-1, at 14-16 (1997) ("1997 BECo Decision"); Norwood Decision, EFSB 96-2, at 11-12 (1997); 1991 NEPCo Decision, 21 DOMSC 325, 339. Here, for the first time, an electric company has presented and applied reliability criteria based on the loss of two supply system components during a single contingency. NEPCo has set forth its criteria for unacceptable exposure to a common mode outage, based on the degree of vulnerability to and the likely consequences of such a contingency. This approach is similar to the Company's approach to setting reliability criteria for a single outage contingency in that both approaches address the consequences of outages in terms of their duration. However, while the single contingency outage criteria focus on a short-duration threshold coupled with an affected load threshold to establish unacceptable consequences of an outage, the common-mode outage criteria focus solely on a longer duration threshold -- 24-hour duration in this case -- to establish unacceptable consequences. The common-mode outage criteria also place more emphasis on

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11 The Company stated that its system design criteria for firm supply requires that: (1) the "nonfirm peak load in a contiguous area ... not exceed 30 [megawatt] MW" and that "a 3-hour outage once in three years, or a 24-hour outage once in ten years ... not [be] exceeded for load above 20 MW" (Exh. NEP-1, Appendix C, § 2.5.1). The Company explained that a supply is considered firm if loss of a single element will not cause a loss of load for longer than the time required for automatic switching (id.).

evaluating the vulnerability to outage.

The Siting Board agrees that the Company's inclusion of a criterion regarding a common mode outage in its service reliability and system design criteria is reasonable. Although the Company's criteria for common-mode outage and single contingency outage place different emphasis on the two indicators of outage consequence -- duration and affected load -- both sets of criteria include provisions to ensure that both outage duration and affected load are taken into account. It is also reasonable that the Company's common mode outage criteria put significant emphasis on evaluating the vulnerability to outage, as the risk of common mode outage can vary greatly based on facility configuration.

Accordingly, the Siting Board finds that the Company's reliability criteria, including its common mode outage criteria, are reasonable for purposes of this review.

b. Configuration and Contingency Analysis

In this Section, the Siting Board considers whether there is a need for additional energy resources based on the Company's reliability criteria, including its reliability criteria with regard to common mode outages.

NEPCo stated that Quincy is the only major load center served by the NEES companies where its entire load, or a major part of the load, is susceptible to a common mode, double-circuit cable failure of significant duration, with unacceptable consequences for customers (Exh. NEP-1, at 2-11).

The Company also addressed a separate future need for additional energy resources related to expected deficiencies in facilities linking the regional 345 kV system ("bulk transmission system") to the regional 115 kV system within the southeastern Massachusetts area (id. at 2-22; Tr. 1, at 18-21). The Company noted that this future need could be met, for a period of time, by one of the identified approaches for meeting the need relative to common mode outage exposure in Quincy -- specifically the Company's proposed project (NEP-1, at 2-22; Tr. 1, at 18-21).

With respect to the need based on susceptibility to common mode outage, the Company explained that the City of Quincy is an electrically isolated area of significant load, supplied through two underground pipe-type 115 kV transmission cables from BECo's Edgar Station in Weymouth to its Field Street substation in southeastern Quincy (Exh. NEP-1, at 2-1 to 2-2). The Company indicated that each of the existing parallel pipe-type underground cables has a summer long-term emergency capability of 239 megavoltamperes ("MVA")[12] and could easily handle the entire Quincy load for the foreseeable future[13] in the event one of these cables were out of service (id. at 2-6).

The Company also stated that two parallel, self-contained underground cables extend from the Field Street substation to the North Quincy substation (id. at 2-1 to 2-2). The Company indicated that each of these cables has a summer long-term emergency capability of 93 MVA, and thus could easily handle the entire North Quincy substation load in the event one of these cables were out of service (id.).[14]

The Company presented evidence describing the exposure to common mode outages of its 115 kV facilities that supply Quincy (id.). The Company stated that each pipe-type cable is contained within an 8-inch diameter steel pipe of 1/4-inch thickness (id.). The Company stated that the self-contained cables are surrounded by a plastic-coated aluminum sheath of 1/10-inch thickness (id.). The Company also stated that both types of cables are buried in thermal sand, and protected by a 4-inch thick concrete cap (id.). The Company added that the typical separation of the parallel cable assembly is 18 inches between cable centers, and the typical burial depth is approximately 42 inches (id. at 2-7).

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12 The Company explained that because the power system in Quincy is operated close to unity power factor, 1 MVA is approximately equal to 1 MW (Exh. NEP-1, at 2-6).

13 The Company stated that the aggregate Quincy peak load was 130 MW during the summer of 1996, and is projected to reach 180 MW in the year 2016 (Exhs. NEP-1, at 2-6; HO-N-3b).

14 The Company stated that during the Quincy aggregate peak load of 130 MW in 1996, each self-contained cable transferred approximately 25.5 MVA to the North Quincy substation (Exh. HO-N-3b). Based on both the Company's load apportionment and projected loading of the North Quincy substation, the Siting Board notes that in the year 2016, the self-contained cable(s) would be required to carry 72 MVA. The Siting Board further notes that either self-contained cable could carry this load based on the Company's long-term emergency rating of 93 MVA for each cable.

In assessing the physical vulnerability of the existing 115 kV underground cables to a double-circuit outage, the Company divided the route into three sections that included (1) the 0.2-mile section of pipe-type cables underneath the Fore River[15] between Edgar Station and Quincy, (2) the 1.9-mile section of pipe-type cables buried beneath city streets in Quincy, and (3) the 3.3-mile section of self-contained cables also buried beneath Quincy streets (id.). The Company concluded that while the 0.2-mile section under the Fore River was not particularly vulnerable to cable damage, seven locations along the underground route of both the pipe-type and self-contained cables are susceptible to damage (id.). The Company explained that in these areas, due to subsurface obstructions, the cables are within two feet of the street surface pavement, and thus within the range of pavement cutting saws (id.). The Company added that because the on-center separation of the parallel cables is approximately 18 inches, the severing of both cables due to a common construction activity, such as excavation, is possible (id.).

The Company asserted that the underground transmission supply cables in Quincy are much more subject to common mode failure than they were at the time of their installation in 1973 because underground construction activities adjacent to the cable route have increased substantially in the last few years (id.). The Company explained that new commercial and industrial customers along the route who require services from various utilities accounted for the increase in such activities (id.).[16]

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15 The Company stated that it reviewed an Army Corps of Engineers sounding survey of the Fore River and was able to determine that the cables crossing the river are buried deep enough below the river bottom to make it very unlikely that the cables could be damaged by dredging, or anchors dragging (Exh. NEP-1, at 2-7). The Company further stated that the cables cross the Fore River in a constricted area adjacent to the Route 3A Bridge, thereby decreasing the likelihood that a ship would drop anchor in the immediate vicinity (id.).

16 The Company stated that the number of "Dig-Safe" requests made by various utilities for construction to serve, upgrade, and/or maintain facilities along the cable route was 340 percent higher in 1996 than in 1990 (Exh. NEP-1, at 2-7). The Company indicated that in spite of diligent attention to the Dig-Safe program, one of the 115 kV self-contained cables in Quincy was severely damaged and the other cable was superficially damaged by a contractor in 1987 (id.).

To assess the degree of cable vulnerability, the Company presented expected failure rates for its pipe-type and self-contained cables (id. at 2-8 to 2-9).[17] The Company estimated that the common mode failure rate is 1 in 2000 years for the pipe-type cables between Edgar Station and the Field Street substation, and about 1 in 60 years for the self-contained cables between the Field Street and North Quincy substations (id.). The Company stated that even though the expected failure rate for the pipe-type cables is much lower than that of the self-contained cables, it still regarded the potential of a double-circuit, pipe-type cable failure as serious (id.). The Company explained that its concern is due to the likely duration of a pipe-type outage, and the number and type of customers affected (id.). The Company stated that the annual average duration of interruption per MECo customer has been approximately 89 minutes over the past five years (id. at 2-10). The Company added that a common mode failure event on the existing facilities would increase MECo's per customer interruption duration in that year by a factor of one and a half to eight times (id.).

The Company next presented its assessment of the consequences of a common mode failure for its pipe-type and self-contained cables (id. at 2-9). The Company stated that such a failure would result in an interruption of electric service for three days or longer, affecting 40,000 customers with failure of the pipe-type cables supplying the aggregate Quincy load, and 20,000 customers with failure of the self-contained cables supplying North Quincy (id.).[18]

In addition, NEPCo stated that it studied the needs of the southeastern Massachusetts transmission system which supplies Quincy and other area utilities serving communities south of Quincy (id. at 2-22). NEPCo stated that those studies indicated that it will be necessary to

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17 NEPCo stated that it based these estimates on Edison Electric Institute data pertaining to forced outages of underground cables (Exh. NEP-1, at 2-8).

18 The Company stated that because Quincy is the primary commercial and industrial center in the South Shore area, many of the electric customers provide jobs and services to the surrounding areas, thereby amplifying the effects of a long-term interruption of electric service beyond the City itself (Exh. NEP-1, at 2-9). The Company noted that although a large number of North Quincy customers are residential, several regional employers would also be affected, including the State Street Bank office complex, Boston Scientific, and Industrial Heat Treating (id.).

modify the regional transmission system to reinforce the power supply system (id.). Specifically, the Company testified that the primary link between the bulk (345 kV) transmission system and the 115 kV transmission system is a single 400 MVA, 345/115 kV transformer at Holbrook substation (Tr. 1, at 19). The Company's witness, Mr. Shastry, testified that in the event the transformer at Holbrook substation fails, 115 kV backup ties from the Auburn Street substation could become overloaded (id.). Mr. Shastry added that because there would be a need to reduce some of the 115 kV load at Holbrook substation under that contingency, the proposed project would transfer the Quincy load portion to the northern portion of the BECo transmission system using Dewar Street as the tie source (id.). Another Company witness, Mr. Smith, testified that in the event the proposed project were not constructed, installation of a second 345/115 kV transformer at Holbrook would likely be required to alleviate the potential overloading (id. at 19-20).

The record indicates that NEPCo's existing transmission and distribution facilities are not subject to overloading either under normal operating conditions, or during a single contingency affecting one of the two underground transmission lines that presently supply Quincy. Further, the record demonstrates that the present Quincy supply configuration is a firm supply under the Company's criteria, and would operate as such under a single contingency event on either of the two lines. However, the record also demonstrates that the close proximity of the two existing underground lines, both to each other and to the pavement surface in some areas along the route, render them vulnerable to damage. Physical damage of significant magnitude, such as a backhoe penetrating both cables, presents a potentially very serious outage scenario to the City of Quincy, with related impacts to the larger South Shore community. Under a double-circuit outage, there would be a loss of power for a minimum of three days to either the entire City of Quincy or a large portion of Quincy, depending on where the common mode failure were to occur. This condition is in direct contravention of the Company's reliability criteria which seeks to limit such an outage to 24 hours. Accordingly, the Siting Board finds that the Company has established that supply to Quincy's two substations -- Field Street and North Quincy -- does not meet the Company's reliability criteria with respect to common mode outages.

In addition, the record indicates that the addition of energy resources to supply Quincy could alleviate potential overloading elsewhere on the southeastern Massachusetts transmission system within the next ten years by providing an independent 115 kV supply source for Quincy, thereby relieving contingency load on equipment at Holbrook substation. The Siting Board addresses benefits of the proposed project to the regional transmission system in Section II.B., below.

Consequently, the Siting Board finds that there is a need for additional energy resources based on the Company's reliability criteria with respect to common mode outages.

c. Accelerated Conservation and Load Management

G.L. c. 164, § 69J requires a petitioner to include a description of actions planned to be taken to meet future needs and requirements, including the possibility of reducing requirements through load management. The Company stated that the total Quincy load of 130 MW in 1996 accounted for approximately 60 percent of the entire South Shore PSA load, which it estimated at approximately 217 MW in the same year (Exh. HO-N-15c). The Company indicated that the Quincy load is approximately 32 percent residential and 68 percent commercial and industrial (Exh. HO-N-8). The Company also indicated that acceleration of both its conservation and its load management programs[19] could not substitute for an additional

[19] 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 C.M.R., § 10.02. For example, a utility may reach an agreement with a manufacturer that uses electricity whereby that manufacturer will curtail its use during peak times when the utility's system, as a whole, is facing increasing demands for electricity for cooling or heating purposes. During non-peak times the manufacturer may then resume its use of electricity. The utility providing electricity has, therefore, managed its load, thereby decreasing its need for additional peak capacity.

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

electrical supply for Quincy given the large amount of load reduction that would be required to alleviate the concern of a common mode outage (Exh. NEP-1, at 2-11, n.4). The Company stated that its distribution affiliate, MECo, has been implementing a DSM program in Quincy, and added that its related load forecasts include the expectation that the DSM program will continue (id.).

The Siting Board notes that the need for the proposed facility is based, not on potential load growth or facility overloads, but on the unacceptable impacts of a minimum three-day power loss to much or all of the City of Quincy in the event of a common mode failure. Even the most aggressive pursuit of DSM will not reduce the likelihood of a common mode failure, the duration of the resulting power outage, or the number of customers affected. Therefore, the Siting Board concludes that accelerated conservation and load management ("C&LM") efforts would not eliminate the need for additional energy resources based on the Company's reliability criteria.

d. Consistency with Approved Forecast

i. Description

G.L. c. 164, § 69J requires that a jurisdictional facility be consistent with an electric company's most recently approved long-range forecast. As described above, the need for the proposed facility is based primarily on the configuration of transmission facilities serving the City of Quincy, rather than on projections of load growth. To satisfy the statutory requirement, the Siting Board reviews the consistency of the Company's analysis of need in this proceeding with its forecast of system load.

NEPCo stated that the petition for the proposed facilities as described in its filing is consistent with the most recent Department-approved forecast -- the 1994 long-term system forecast filed by MECo, NEPCo's retail affiliate ("1994 forecast") in D.P.U. 94-112 (1994) (Exh. HO-N-6b(s); Tr. 1, at 27-30). The Company stated that MECo filed two subsequent forecasts with the Department, one in 1995 and one in 1996, that updated components of the 1994 forecast, and added that both were methodologically consistent with the 1994 forecast

(Exh. HO-N-14; Tr. 1, at 27-28).[20] The Company further stated that the PSA is the smallest unit for which it regularly develops forecasts (Exh. HO-N-6b). The Company indicated that the 1994 South Shore PSA load growth forecast used in this proceeding is consistent with the 1994 forecast (Exhs. HO-N-6b(S2); HO-A-2, Att. 1; Tr. 1, at 30).[21]

The Company stated that it conducts facility planning by developing projections of peak load growth for an area within a PSA (Exh. HO-N-15c). The Company indicated that it developed an updated load forecast for Quincy by apportioning future load within the South Shore PSA proportional to recent peak demands (id.). The Company indicated that facility area projections include the highest recorded area peak load, anticipated large new load additions, and the expected (50 percent probability) PSA peak load growth rate (id.).

The Company provided historical and forecast peak loads for the MECo system and the South Shore PSA for the years 1992 through 2000 (Exhs. HO-RR-2, Att. 1; HO-RR-3).[22] The

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20 The Company's witness, Mr. Lowell, testified that in 1995, MECo filed an Integrated Resource Plan ("IRP") that updated the load forecast and other components of the 1994 filing (Tr. 1, at 27-28). Mr. Lowell explained that although the forecast that accompanied the 1995 IRP was not subsequently acted upon by the Department, it used essentially the same methods, models, and tools used for preparing the approved 1994 forecast (id.). Mr. Lowell added that updated information included economic drivers and demographic changes within the affected service territory (id. at 28). With respect to the 1996 IRP filing, Mr. Lowell stated that only minor adjustments were made updating the previous 1995 long-term forecast filing relative to the first one or two years of the forecast (id.). NEPCo noted that the Department chose not to adjudicate IRP filings after 1994 (id. at 30-31).

21 The Company identified the original forecast supporting the selection of the proposed supply plan as that contained in Section 2.3 (Load Forecast/Cable Capability) of the Third Quincy 115 kV Supply Study prepared by the Company's affiliate, New England Power Service Company, and dated January, 1995 (Exh. HO-A-2, Att. 1).

22 For the South Shore PSA, the Company provided this information relative to both coincident and non-coincident peak load levels, and indicated that the non-coincident peaks were slightly higher than the coincident peaks for every historical and forecast year included (Exh. HO-RR-2, Att. 1). With respect to the system wide forecast, the Company indicated that historical and projected summer peak loads ranged from 2,734 megawatt ("MW") to 3,014 MW between 1992 and 1996, while actual loads

(continued...)

Company also provided historical and forecast peak load for the City of Quincy for the years 1989 to 2016, based on MECo's most recent PSA forecast (Exh. NEP-1, at 2-4 to 2-5). The Company noted that the City of Quincy represents approximately 60 percent of the South Shore PSA load based on 1996 peak loads of 130 MW in Quincy and 217 MW in the South Shore PSA (Exh. HO-N-15c). The Company stated that load growth in the City of Quincy is forecasted to occur at a rate of 1.1 percent annually to the year 2006 (Exhs. NEP-1, at 2-4 to 2-5; HO-N-6a). Finally, the Quincy peak load forecast indicated that by the year 2016, the expected Quincy peak load[23] would be approximately 168 MW, while a high peak load forecast would be 180 MW (Exh. NEP-1, at 2-5, Figure 2-3).

ii. Analysis

In forecasting load for the two Quincy substations, the Company first relied on the 1994 MECo South Shore PSA forecast, which is based on forecast methods consistent with the Department-approved 1994 long-term system forecast. The Company then derived the Quincy substations' forecast from the MECo PSA forecast, based on the historical relationship of the Quincy substations' peak load to the PSA peak load. The Company adequately explained the PSA and sub-area specific adjustments that were applied to account for load data that would otherwise not be reflected in the forecast models. Thus, the Company relied on both quantitative and judgmental techniques in its forecast of PSA and area load growth. Further, the Company has provided a reasonable explanation for its estimation of load growth at the substation level, based on the PSA forecast. The Company's Quincy load forecast reflects

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22 (...continued)
reached as high as 3,039 MW (id.). Regarding the South Shore PSA load during the same years, the Company indicated that the actual non-coincident peak load ranged from 216 MW to 238 MW (id.).

23 The Company's assumed growth rate in Quincy results in an expected peak load of approximately 168 MW in the year 2016 (Exh. NEP-1, at 2-5, Fig. 2-3). The Company also presented a high-forecast projection of 180 MW in that same year (id.). For the years 2006-2016, the Company indicated that it assumed an average growth rate of 1.1 percent for the expected forecast, and 1.7 percent for the high forecast (id.).

some future expansion of existing load, at an average annual rate of approximately one percent. As was previously discussed in Section II.A.3.b, above, the proposed facilities are needed based on existing facility configurations and load levels. Accordingly, for purposes of this review, the Siting Board finds that the Company's load forecast methodology is reasonable and acceptable.

Also, as discussed above, the need for the identified facilities is based, not on the precise load projected for a specific future year, but on the unacceptable consequences of a three-day power loss to some or all of the City of Quincy in the event of a common mode failure. The Company's description of the impacts of such a power loss to a load of approximately 130 MW is consistent with the load forecasts contained in the 1994, 1995, and 1996 filings with the Department. Consequently, the Siting Board finds that the Company's identification of a need for additional energy resources in Quincy is consistent with its most recently approved long range forecast.

e. Conclusions on Reliability of Supply

The Siting Board has found that the Company's reliability criteria, including its common mode outage criteria, are reasonable for purposes of this review. The Siting Board also has found that the Company has established that existing supply to Quincy's two substations does not meet the Company's reliability criteria with respect to common mode outages. Consequently, the Siting Board has found that there is a need for additional energy resources based on the Company's reliability criteria with respect to common mode outages.

In addition, the Siting Board has found that accelerated C&LM efforts would not eliminate the need for additional energy resources based on the Company's reliability criteria. Further, the Siting Board has found that the Company's load forecast methods are reasonable and acceptable for purposes of this review. Finally, the Siting Board has found that the Company's identification of a need for additional energy resources in Quincy is consistent with its most recently approved long range forecast.

Based on the foregoing, the Siting Board finds that the Company has demonstrated that the existing supply system is inadequate to supply existing load supplied by the Edgar Station under certain contingencies. Accordingly, the Siting Board finds that additional energy resources are needed for reliability purposes in the City of Quincy.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, § 69 H requires the Siting Board to evaluate proposed projects in terms of their consistency with providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost. In addition, G.L. c. 164, § 69 J requires a project proponent to present "alternatives to planned action" which may include: (a) other methods of generating, manufacturing, or storing; (b) other sources of electrical power or natural gas; and (c) no additional electric power or natural gas.[24]

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the identified need. 1997 BECo Decision, EFSB 96-1, at 37; 1997 ComElec Decision, EFSB 96-6, at 22; Boston Edison Company, 13 DOMSC at 63, 67-68, 73-74 (1985). In addition, the Siting Board requires a petitioner to consider reliability of supply as part of its showing that the proposed project is superior to alternative project approaches. 1997 BECo Decision, EFSB 96-1, at 38-42; 1997 ComElec Decision, EFSB 96-6, at 23; Massachusetts Electric Company, 18 DOMSC at 383, 404-405 (1989).

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

2. Identification of Project Approaches for Analysis

The Company considered six alternative approaches for meeting the identified need in Quincy (Exh. NEP-1, at 2-11).[25] The Company identified Plans 1, 2, and 3 as transmission and distribution supply alternatives, and Plans 4, 5, and 6 as generation alternatives (id. at 2-11 to 2-14). The Company indicated that the Quincy peak load reached 130 MW during 1996 and is projected to reach approximately 150 MW by 2005 (id. at 2-5).

a. Plan 1 - The Proposed Project

Plan 1 ("proposed project") would establish a new 180 MW capacity, 115 kV transmission supply to Quincy via two new 3.3-mile underground transmission lines from BECo's Dewar Street substation to NEPCo's North Quincy substation (id. at 2-12, 3-8, 3-21). The Company indicated that the proposed project would include a 1,300 foot directional-drill crossing of the Neponset River, and installation in streets for approximately one-third of the route (id. at 1-2, 2-21, 3-26). The Company further indicated that the proposed project would cost $26.1 M, and provide a full backup of Quincy load as projected by NEPCo until the year 2016 (id. at 2-21).

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25 NEPCo stated that it also considered both No Build and C&LM options (Exh. NEP-1, at 2-11, n..4). With respect to the No Build option, the Company stated that any options to provide an additional source of electrical supply to Quincy would, by their nature, require some form of additional facilities (id.). The Company stated that the No Build option could not address the identified need and therefore was not considered further (id.).

With respect to C&LM, the Company indicated that its affiliate, MECo, has been implementing a C&LM program in Quincy (id.). The Company further stated that the Quincy load growth forecasts include the expectation that the C&LM program will continue (id.). However, the Company added that C&LM efforts cannot substitute for an additional electrical supply and therefore were not considered further (id.). See Section II.A.3.c, above.

b. Plan 2

Plan 2 would establish a new 151 MW capacity supply with a 2.0-mile length of 115 kV transmission line from BECo's Edgar Station in Weymouth to NEPCo's Field Street substation in Quincy, and would also involve rearranging the existing low-voltage facilities and adding new low-voltage cables for a length of approximately 3.3 miles between the Field Street, Wollaston, and North Quincy substations (id. at 2-14, 2-23). The Company indicated that Plan 2 would cost $23.2 M and provide a full backup of Quincy load until 2006 (id. at 2-21).

The Company stated that it considered various routing options for the 115 kV line required under Plan 2, all of which would involve significant impacts to either built-up areas or natural resources (id. at 2-23).[26] The Company explained that it investigated an all-water route, and land and water routes, as well as all-street routes (id.). The Company stated that no route could be identified that did not have a potentially significant environmental impact such as long crossings of navigable waters, shellfish beds, and parkland, or lengthy segments along primary commuter routes or secondary streets (id.). The Company also noted that the installation under Plan 2 of the additional 3.3 miles of low-voltage underground cables between the Field Street and North Quincy substations would consist largely of in-street construction which would cause significant community disruption (id.).

c. Plan 3

Plan 3 would provide an additional 151 MW of supply capacity through reinforcement of the existing 2.0-mile, low-voltage cables from BECo's Edgar Station, and improvements to Edgar Station and the Fore River utility tunnel (id. at 2-14, 2-24). The Company indicated that Plan 3 also would require the installation of 3.3 miles of low voltage cable between the

26 The Company stated that, with the exception of an occasional vacant lot and some park land, the area is fully developed with industrial, commercial, residential, and waterfront developments (Exh. NEP-1, at 2-23). The Company added that Route 3A (Washington Street and Southern Artery), one of the primary commuter routes between Boston and the South Shore area, is the only major roadway through the area (id.).

Field Street, Wollaston, and North Quincy substations (id. at 2-16). The Company stated that Plan 3 would cost $22.6 M and provide a full backup of Quincy load until 2006 (id. at 2-21).

d. Plan 4

Plan 4 would involve the construction of 160 MW of combustion turbine generation ("CTG") capacity at the Field Street substation site, and the installation of a low-voltage link between the Field Street and North Quincy substations via the Wollaston substation (id. at 2-14, 2-17). The Company indicated that Plan 4 would cost $61.2 M and provide a full backup of Quincy load until approximately 2010 (id. at 2-5, 2-21). The Company stated that it eliminated consideration of Plan 4 because it would cost substantially more than the proposed project, Plan 2, or Plan 3, and would provide no clear reliability or environmental advantage (id. at 2-22).

e. Plan 5

Plan 5 would interconnect the North Quincy substation with the Deer Island Facility in Boston via 6.5 miles of underwater and underground 115 kV cable beneath the Neponset River (id. at 2-14, 2-18, 2-20). The Company stated that this interconnection would provide access to 110 MW of spare emergency generation capacity at Deer Island (id. at 2-20). The Company indicated that Plan 5 would cost $36.9 M, but would not be capable of fully serving the present load requirements for the City of Quincy (id. at 2-5, 2-21). The Company stated that it eliminated consideration of Plan 5 because it would cost significantly more than the proposed project, Plan 2, or Plan 3, and would provide no clear reliability or environmental advantages (id. at 2-22).

f. Plan 6

Plan 6 would interconnect the North Quincy substation with the Potter Generating Station in Braintree via 6.0 miles of underground 115 kV cable (id. at 2-14, 2-19 to 2-20). The Company stated that this interconnection would provide access to 103 MW of spare emergency generation capacity at the Potter Generating Station (id. at 2-20). The Company indicated that Plan 6 would cost $34.9 M, but like Plan 5, it also would not fully serve present Quincy load requirements (id. at 2-5, 2-21). The Company stated that it eliminated consideration of Plan 6 because it would cost significantly more than the proposed project, Plan 2, or Plan 3, and would provide no clear reliability or environmental advantages (id. at 2-22).

g. Analysis

The Company has identified six possible project approaches, of which four -- the proposed project and Plans 2, 3, and 4 -- would fully serve projected Quincy load requirements through 2006 or later. The Siting Board agrees with the Company's conclusion that the generation plans -- Plans 4, 5, and 6 -- do not warrant further evaluation based on their relatively high costs and lack of offsetting reliability or environmental advantages over the proposed project and Plans 2 and 3.

With respect to the Company's three transmission and distribution project options, the Siting Board notes that Plans 2 and 3 exhibit a lower aggregate cost relative to the Company's preferred plan. However, considerable construction-related impacts to fully developed or environmentally sensitive areas would occur along the longer 5.3-mile route of Plan 2. The record demonstrates that the impacts to both the human and natural environments under Plan 2 would far outweigh the identified cost savings. Therefore, the Siting Board focuses on the two remaining transmission and distribution supply configurations -- the proposed project and Plan 3.

Accordingly, the Siting Board finds that both the proposed project and Plan 3 would meet the identified need in Quincy. In the following sections, the Siting Board compares the proposed project and Plan 3 with respect to reliability, environmental impacts, and cost.

3. Reliability

In this section, the Siting Board compares the proposed project with Plan 3 with respect to their ability to provide a reliable supply of electricity to the City of Quincy (see Section II.A.3.a, above).

The Company indicated that both the proposed project and Plan 3 could meet the identified need, although the proposed project could back up Quincy load until 2016, while Plan 3 could only do so until 2006 (Exh. NEP-1, at 2-21). The Company stated that only the proposed project would provide a new 115 kV connection between the northern and southern portions of the BECo system, thereby enhancing the reliability of electrical supply to both the City of Quincy and the City of Boston (Exh. NEP-1, at 2-22 to 2-23). The Company further stated that the proposed project would be capable of providing partial electrical backup to the Dewar Street substation if certain additions were made to the BECo transmission system (id.).

Regarding a separate reliability concern on the area 345 kV transmission system supplying southeastern Massachusetts (see Section II.A.3.b, above), the Company stated that the proposed project, but not Plan 3, could defer from 2005 until 2022 the need to make improvements at the Holbrook substation (Exh. HO-RR-12a; Tr. 1, at 113-116). Because improvements to address this reliability concern are already planned, the Company further addresses the deferral of those improvements as an economic savings (see Section B.5, below).

As previously found in Section II.A.3.b, above, Quincy is vulnerable to a common-mode outage affecting the two 115 kV underground transmission lines that presently are the city's only source of electricity. While any additional avenue of supply would likely diminish this vulnerability, in whole or in part, the record demonstrates that the proposed project would fully backup the Quincy load until 2016 while Plan 3 would be capable of doing so only until 2006. The record also demonstrates that the proposed project would provide other reliability advantages to area transmission systems by linking BECo's Boston service area to adjacent south shore service areas, including: (1) partial backup of the Dewar Street substation, and (2) backup to relieve load on a large 345 kV autotransformer at the Holbrook substation, thereby delaying the need for other corrective measures for an additional 17 years.

Accordingly, the Siting Board finds that the proposed project would be preferable to Plan 3 with respect to reliability.

4. Environmental Impacts

In this Section, the Siting Board compares the proposed project to Plan 3 with respect to environmental impacts resulting from: (1) facility construction; (2) permanent land use; and (3) magnetic field levels.

a. Facility Construction Impacts

NEPCo argued that the proposed project is environmentally superior to Plan 3 with respect to construction related impacts (Company Brief at 16). In support, the Company stated that the proposed project's 3.3-mile underground cable route between the Dewar and North Quincy substations would primarily run behind commercial lots or use open highway corridors, open space, and low-volume roadways, thereby minimizing disruption to natural resources and urban environments (Exhs. NEP-1, at 2-23; HO-A-13a). The Company stated that exceptions would include the crossing of Morrissey Boulevard and trenching along Victory Road (Exh. HO-A-13a). The Company further stated that the proposed route in Quincy would cross Squantum Point Park and extend along Commander Shea Boulevard, a low-volume roadway (id.). The Company noted that the proposed project would cross both the Neponset River (via horizontal directional drilling) and Billings Creek, but asserted that no serious impact to either waterbody is expected (id.).

With respect to Plan 3, the Company stated that construction impacts associated with reinforcing the existing low-voltage cables between Edgar Station and Field Street substation would be minor (id.). The Company explained that new 23 kV cables would be installed in an existing utility tunnel passing under the Fore River, extending approximately two miles to a new manhole at the intersection of Washington Street and McGrath Highway (id.; Exh. HO-A-12, Att. 1). The Company added that no additional cables would be necessary along McGrath Highway and Brackett Street to the Field Street substation (Exh. HO-A-12). However, the Company stated that road opening and trenching operations would be necessary to upgrade or install underground distribution facilities between the Field Street, Wollaston, and North Quincy substations (id.). The Company noted that these distribution facilities would proceed northwesterly along Route 3A (Southern Artery), crossing Furnace Brook Parkway and Merrymount Park, and then proceed northwesterly beneath Fenno Street and other neighborhood streets in Quincy, terminating at the North Quincy substation for a total of 3.3 miles (id., Att. 1; Exh. HO-A-6).[27] The Company added that land use along the Plan 3 distribution facilities route is a combination of commercial and residential along the major roadways of Route 3A and Hancock Street and several of the minor roadways, while most of the local streets are residential (Exh. HO-A-12).

The Company stated that the proposed project also would require extending the existing Dewar Street substation facility by 4,000 square feet to accommodate foundations for new electrical equipment[28] and the layout of the new underground cables (Exh. NEP-1, at 3-31). The Company added that construction at the Dewar Street substation would occur over approximately six months but that the work would not be continuous (id.). The Company stated that the proposed project also would require extending the North Quincy substation facility by approximately 20,000 square feet, requiring that existing landscape trees be cleared, and that piles be driven to support new equipment foundations (id. at 3-28 to 3-30; Exh. HO-A-13b). The Company stated that residences are located on one side of the North Quincy substation (Exh. HO-A-13b). The Company added that work on the North Quincy substation addition would occur over an 18 month period but would not be continuous (Exh. NEP-1, at 3-28 to 3-30).

The Company indicated that Plan 3 would involve construction at three substations -- the Edgar Station, Field Street, and Wollaston substations (Exh. HO-A-13b).[29] The Company stated that facility additions and modifications at all three substations could be accommodated in existing cleared space, thereby minimizing construction impacts (id.). The Company also

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27 NEPCo stated that the Plan 3 distribution facilities would traverse Merrymount Park for approximately 0.5 mile (Exh. HO-A-12).

28 NEPCo stated that the new equipment would include high voltage bus supports, disconnect switches, and circuit breakers (Exh. NEP-1, at 3-31).

29 The Company indicated that existing low-voltage lines from Wollaston substation to North Quincy substation would be reconductored under Plan 3 (Exh. NEP-1, at 2-13, 2-16).

stated that the greatest potential for substation construction impacts would be at the Wollaston substation, due to the presence of residences on three sides of the substation (id.).

The record indicates that Plan 3 would involve installation of underground distribution cables along 3.3 miles of city streets between Field Street, Wollaston, and North Quincy substations, resulting in considerable construction impacts to the affected communities. In contrast, construction of the proposed project, which is routed along open highway corridors and low-volume roadways and through open space, would have minimal community impacts. Further, significant substation work to accommodate the cable reinforcements would be necessary at three substations under Plan 3 -- Edgar Station, Field Street, and Wollaston -- while the proposed project would require such work at only the Dewar and North Quincy substations. However, substation construction under the proposed project would require a larger extent of expansion than under Plan 3, and would include limited clearing of trees and installation of piles at the North Quincy substation. On balance, the Siting Board concludes that the potential construction impacts of the installation of 3.3 miles of distribution cable outweigh the tree clearing and pile driving impacts associated with the proposed project. Accordingly, the Siting Board finds that the proposed project would be preferable to Plan 3 with respect to facility construction impacts.

b. Permanent Land Use and Community Impacts

NEPCo asserted that the permanent land use impacts of Plan 3 would be slightly greater than those of the proposed project (Exh. HO-A-13b). The Company stated that the occupants of residences located on three sides of the Wollaston substation could experience permanent land use impacts (id.). Specifically, the Company noted that Plan 3 would require expansion at the Wollaston substation, which is located in a mixed commercial and residential area, and that new facilities would be sited in what is presently an open but unused portion of the substation yard visible to residential neighbors (id.). The Company stated that significant amounts of this open space would be transformed into a view of mechanical/electrical structures, including two 23/13.8 kV, 20 MVA transformers and four 13.8 kV feeder cables with circuit breakers, but acknowledged that landscaping could partially shield such views (id.). The Company added that the operation of two new transformers would be a new noise source at the Wollaston substation, potentially impacting the surrounding area (id.). The Company indicated that no permanent impacts are anticipated at either Edgar Station or the Field Street substation due to the commercial/industrial land use in the immediate area (id.).

The Company indicated that the proposed project would require changes to the Dewar Street and North Quincy substations (Exh. NEP-1, at 2-13). The Company indicated that BECo's Dewar Street substation is surrounded by commercial and industrial uses, and that in conjunction with the approximately 4,000 square foot expansion of the substation, the entrance would be screened by trees, shrubs, and architectural fencing (id. at 3-31; Exh. HO-A-13b). The Company stated that the only new noise source at the Dewar Street substation would be a heat exchanger which, during operation, would be inaudible at the nearest property line or at the nearest residence (Exh. NEP-1, at 3-31). At the North Quincy substation, the Company stated that nearby residences are located on one side of the substation while commercial property and MBTA rail tracks abut the other sides (id. at 3-32; Exh. HO-A-13b). The Company also committed to constructing a wall and additional landscaping in order to minimize the visual impacts of the approximately 20,000 square foot expansion of the substation (Exh. HO-A-13b). The Company indicated that no new permanent noise source would be installed at the North Quincy substation under the proposed project (id.).

The record indicates that NEPCo's proposed transmission line will be located underground along a route that generally avoids areas of sensitive natural environment and urban density, and once sited, would be nearly invisible (see Section III.C.2.a.iv). The record also indicates that associated substation expansions at both the Dewar and North Quincy substations would require the development of an aggregate 24,000 square feet. However, the permanent land use impacts of the proposed project would be minimized due to the location of the Dewar and North Quincy substations near primarily commercial and industrial land uses.

In comparison, the low-voltage lines required by Plan 3 would be located along more heavily travelled major roadways and residential streets, creating the potential for significant traffic interruptions in the event of a fault along such route sections. In addition, the record indicates that installation of new facilities, including two new transformers, likely would result in noise and visual impacts affecting residences on three sides of the facilities at Wollaston substation. The Siting Board also notes that the major new equipment required there under Plan 3, relative to the Wollaston substation's present footprint in that community, would be significant. Thus, the record indicates that overall permanent land use impacts under Plan 3 would be greater than those under the proposed project.

Accordingly, the Siting Board finds that the proposed project would be preferable to Plan 3 with respect to permanent land use and community impacts.

c. Magnetic Field Levels

The Company stated that the existing transmission cables that presently supply the Field Street and North Quincy substations from Edgar Station and the existing low-voltage cables would continue to carry those loads during normal operating conditions, under either the proposed project or Plan 3 (Exh. HO-A-18). The Company therefore concluded that, under normal operating conditions, there would be no difference in the magnetic field levels associated with either the proposed project or Plan 3 (id.).

The Company also assessed the magnetic field levels associated with the proposed project during a common-mode outage (id.). The Company stated that, in the event of an outage affecting the existing supply cables between Edgar Station and the Field Street substation, the proposed project would carry the full Quincy load (id.). The Company stated that under such a contingency, magnetic field levels would be 1.9 milligauss ("mG") directly above the new transmission lines, and 0.7 mG at a distance 10 feet from the new lines (id.; Exh. NEP-1, at 3-45). The Company further stated that in the event of a common-mode failure affecting the existing cables between the Field Street and North Quincy substations, the proposed project would carry only North Quincy substation load -- 40 percent of full Quincy load (Exh. HO-A-18). The Company indicated that under this scenario, the magnetic field levels above the new transmission lines would be well below 1.9 mG (id.). The Company added that the load on the low-voltage lines, and the associated magnetic field levels, would be unaffected by a common-mode outage (id.).

The Company also assessed the magnetic field levels associated with Plan 3 during a common-mode outage (id.). The Company stated that a common-mode outage affecting the existing cables between Edgar Station and the Field Street substation would cause the new low-voltage cables between those substations to carry the entire Quincy load (id.). The Company explained that in such an event, the magnetic field level directly above these low-voltage cable ducts would be significantly higher than 1.9 mG until normal operation was restored (id.). The Company indicated that the higher magnetic field levels would be due to transmission of the entire Quincy load on a 23 kV system that requires proportionally higher line currents, as compared to a 115 kV system (id.). The Company stated that a common-mode failure between the Field Street and North Quincy substations would cause the low-voltage cables from the Field Street and West Quincy substations to carry the Wollaston and North Quincy substations loads, and noted that under such contingency, the magnetic field levels directly above these low-voltage cable ducts also would exceed 1.9 mG until normal operation was restored (id.).

With respect to ongoing EMF research, the Company argued that the current status of research regarding magnetic fields indicates there exists no established causal relationship between power frequency magnetic field exposure and adverse health effects (Company Brief at 22). In support, the Company's witness, Dr. Valberg, testified that recent studies concerning epidemiology (human incidence of disease), animal studies, and "in vitro"[30] studies have failed to establish, confirm, or replicate earlier reported associations of such a relationship, and in some instances, the likelihood of such a relationship has actually been diminished (Tr. 2, at 43-46, 63).[31]

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30 Dr. Valberg explained that "in vitro" studies are laboratory studies that may analyze biological systems modeled in a cellular fashion or biochemical systems containing the molecules that support life (Tr. 2, at 43).

31 Dr. Valberg testified that the results of recent epidemiological studies have additionally weakened some of the associations previously asserted as indicators of potential or likely causal factors of adverse health effects from EMF (Tr. 2, at 44). Dr. Valberg also testified that a 1997 Canadian study of animals in which subjects were exposed to (continued...)

The record indicates that the proposed underground 115 kV transmission lines would not emit any magnetic fields under a normal Quincy supply condition. In the event of a common-mode outage or other such contingency, the record indicates that, for the duration of the outage, there would be a maximum magnetic field level above the proposed new underground pipe-type transmission lines of 1.9 mG, and 0.7 mG at a distance of 10 feet from the center line over the proposed cables. Under Plan 3, a common-mode outage or similar contingency would result in temporarily increased magnetic field levels along affected back-up supply routes, many of which traverse residential neighborhoods. While the record does not indicate the expected magnetic field levels under the contingency scenario, they are likely to be greater than 1.9 mG due to the higher currents necessary to convey an equal amount of power using lower voltage facilities.

Accordingly, the Siting Board finds that the proposed project is slightly preferable to Plan 3 with respect to EMF.

d. Conclusions on Environmental Impacts

In Sections II.B.4.a, b, and c, above, the Siting Board has found that: (1) the proposed project would be preferable to Plan 3 with respect to facility construction impacts; (2) the proposed project would be preferable to Plan 3 with respect to permanent land use and community impacts; and (3) the proposed project would be slightly preferable to Plan 3 with respect to EMF.

Based on the above analyses, the proposed project is preferable to the Plan 3 alternative. In addition, the record indicates that the capacity of the Plan 3 alternative would be 151 MW,

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31 (...continued)
magnetic fields over the course of their lifetimes demonstrated no bioassay effect (id. at 45). Further, Dr. Valberg indicated that in vitro studies have not, to date, identified a mechanistic pathway by which power line magnetic fields or weak electric fields could alter biology (id.).

Dr. Valberg also noted that no magnetic field level or threshold has been identified by the Massachusetts Department of Public Health, or is otherwise externally cited with regularity as being of concern with regard to health effects (id. at 57-60).

sufficient to meet projected load requirements of the City of Quincy until the year 2006, while the 180 MW capacity of the proposed project would meet projected Quincy load until 2016. The Siting Board notes that the impacts of the Plan 3 alternative, already greater in aggregate to those of the proposed project, could be even greater if the impacts of future projects to meet load growth between 2006 and 2016 are considered. The Siting Board therefore concludes that the record demonstrates a clear environmental advantage for the proposed project relative to the Plan 3 low-voltage supply alternative.

Accordingly, the Siting Board finds that the proposed project would be preferable to the Plan 3 alternative with respect to environmental impacts.

5. Cost

As previously discussed in Sections II.B.2.a and c, above, the Company indicated that the total cost of the proposed project would be $26.1 million, while that of Plan 3 would be $22.6 million (Exh. NEP-1, at 2-21). The Company argued that even though the initial costs of the proposed project are greater than those of Plan 3, the proposed project would provide both an additional 29 MW of capacity for Quincy as well as a long-term regional financial benefit (Company Brief at 14-15). Specifically, the Company stated that with the proposed project it would realize a net present value ("NPV") cost savings of $5 million in 1997 dollars due to the deferral of the planned installation of a second 345 kV autotransformer at Holbrook substation from the year 2005 to 2022: this installation could not be deferred under Plan 3 (Exh. NEP-1, at 2-21 to 2-22; HO-RR-12a; Tr. 1, at 39-42).[32]

The record demonstrates that the net cost of the proposed project (i.e., the Company's estimates of capital costs less the $5 million in savings resulting from the 17 year deferral of a

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[32] The Company's witness, Mr. Shastry, testified that the $5 million figure represents NEPCo's expected 50 percent share of savings with a NPV of $10 million to several Massachusetts utilities/municipal light plants related to the delay of planned reinforcement of the bulk transmission system (Tr. 1, at 18-20, 40-41). Mr. Shastry noted that the aggregate financial benefit of the deferral to Massachusetts ratepayers would be $10 million (id. at 42, 115-116).

345 kV transformer at Holbrook substation), is $21.1 million, or $1.5 million less than the capital cost of Plan 3.

Accordingly, the Siting Board finds that the proposed project would be preferable to Plan 3 with respect to cost.

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

In comparing the proposed project to the Plan 3 low-voltage alternative, the Siting Board has found that both the proposed project and Plan 3 would meet the identified need in Quincy.

The Siting Board has also found that the proposed project would be preferable to Plan 3 with respect to reliability, environmental impacts, and cost. Accordingly, the Siting Board finds that the proposed project is preferable to Plan 3 with respect to providing a necessary energy supply for the Commonwealth, with the least environmental impacts, and at the lowest possible cost.

III. ANALYSIS OF THE PROPOSED AND ALTERNATIVE FACILITIES

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H and J. Further, G. L. c. 164, § 69J requires the Siting Board to review alternatives to planned projects, including "other site locations." In its review of other site locations, the Siting Board requires a petitioner to show that its proposed facilities' siting plans are superior to alternatives and that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability. 1997 BECo Decision, EFSB 96-1, at 57; 1997 ComElec Decision, EFSB 96-6, at 47; 1991 NEPCo Decision, 21 DOMSC at 376.

A. Description of the Proposed and Alternative Facilities

1. Proposed Facilities

NEPCo proposes to construct two 3.3-mile long, underground 115-kV transmission lines in Dorchester and Quincy that will connect BECo's Dewar Street substation in Dorchester to NEPCo's North Quincy substation on Spruce Street in Quincy (Exh. NEP-1, at 1-1; 3-8; 3-21). In addition, the Company proposes to expand the North Quincy substation by 20,000 square feet and the Dewar Street substation to a lesser extent, and to upgrade both the Dewar Street and North Quincy substations by installing 115 kV cable terminals and circuit breakers for the two new transmission lines (Exh. NEP-1, at 1-1, 1-3).

The primary route generally follows the Southeast Expressway from BECo's Dewar Street substation in Boston and along Victory Road (id. at 3-34 to 3-35). From the end of Victory Road, the route extends under the Neponset River to Quincy, then across MDC land to Commander Shea Boulevard, and then south along the Boulevard and under Hancock Street. Finally, it passes under the MBTA tracks to NEPCo's North Quincy substation (id.). At several locations, including the Neponset River crossing, the Company plans to install the proposed two cables by horizontal directional drilling ("HDD") (id.).

2. Alternative Facilities

NEPCo indicated that the alternative route is identical to the primary route from the Dewar Street substation to Victory Road, but that from Victory Road south, the route follows the Southeast Expressway to Conley Street, proceeds west on Conley Street to Tenean Street, continues south on Tenean Street, then heads west, crossing the MBTA tracks to Norwood Street (id. at 3-36 to 3-37). The route continues south on Norwood Street to MDC land bordering Morrissey Boulevard, west across the Boulevard, south along the median strip through Neponset Circle to the bridge abutment, then across the Neponset River along the bridge structure (id.). It then proceeds down the exit ramp to Hancock Street in Quincy, along Hancock Street and across a private right-of-way, and finally terminates inside the enclosure of the North Quincy substation (id.).

B. Site Selection Process

1. Standard of Review

In order to determine whether a facility proponent has shown that its proposed facilities' siting plans are superior to alternatives, the Siting Board requires a facility proponent to demonstrate that it examined a reasonable range of practical facility siting alternatives. 1997 Boston Edison Company Decision, EFSB 96-1, at 59 ("1997 BECo Decision"); 1997 ComElec Decision, EFSB 96-6, at 50; Northeast Energy Associates, 16 DOMSC 335, 381, 409 (1987) ("NEA Decision"). In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. 1997 BECo Decision, EFSB 96-1, at 59; Commonwealth Electric Company, EFSB 96-6, at 50 (1997) ("1997 ComElec Decision"); Berkshire Gas Company (Phase II), 20 DOMSC 109, 148-149, 151-156 (1990). Second, the facility proponent must establish that it identified at least two noticed sites or routes with some measure of geographic diversity. 1997 BECo Decision, EFSB 96-1, at 59; 1997 ComElec Decision, EFSB 96-6, at 50; NEA Decision, 16 DOMSC 381-409.

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

2. Development of Siting Criteria

a. Description

The Company indicated that its site selection process incorporated the following stages: definition of a study area; identification of routing options; identification of routing constraints and opportunities;[33] and ranking of routing options to determine a primary and an alternative route (Exh. NEPCo-1, at 3-2).

The Company indicated that the study area for its proposed project, approximately 12,000 feet long by 4,000 to 6,000 feet wide, was determined by general transit corridors and the most obvious routing options (id.). More specifically, the Company indicated that the northern and southern boundaries of the study area were determined by the location of the interconnecting North Quincy and Dewar Street substations (id.). The Company established the eastern study area boundary to include the Squantum Point area of Quincy, which, the Company asserted, allowed for a reasonable range of geographically and environmentally diverse alternatives, including water routes and routes within a less urban environment (id.). The Company indicated that the eastern study area boundary followed Commander Shea Boulevard, a private way about 4,000 feet to the east of Morrissey Boulevard, the study area "centerline" (id.). The Company stated that the western boundary, which was set along Dorchester Avenue, Adams Street and Neponset Avenue, was approximately 2,000 feet west of Morrissey Boulevard (id.). The Company asserted that to go further west would only lengthen the route unnecessarily and impact more people (id.). The Company stated that the study area included portions of two cities, Boston and Quincy, and encompassed a combination of urban, high density residential/business areas in the central and western sections with open space areas to the east (id.).

The Company stated that conceptual routes for the proposed project were identified initially as part of the Company's Third Quincy 115 kV Supply Study - January, 1995 ("Supply Study") (id. at 3-4). The Company stated that four conceptual routes, including two routes which crossed from Dorchester to Squantum Point in Quincy and two routes in Boston streets crossing into Quincy via the Neponset River Bridge, were presented to regulatory staff,

33 The Company defined routing opportunities as those factors which would facilitate siting and routing constraints as factors which might restrict or inhibit siting in a given location (Exh. NEP-1, at 3-8).

elected officials and neighborhood representatives beginning in the summer of 1995 (id.).[34] The Company indicated that, based on both its discussions with government agencies and the public and on field reconnaissance in the study area, it identified nine routing alternatives for evaluation (see Figure 2, below) (id.).

The Company stated that one of its chief goals in selecting routing criteria was to establish a balance between criteria related to urban environments and criteria related to open space environments, both of which were present in the study area (id. at 3-9).[35] The Company stated that its selected routing criteria included 11 environmental constraints and three environmental opportunities, and that these "environmental evaluation criteria" were used to compare the nine alternative routes previously identified by the Company (id. at 3-13).

The Company indicated that the comparison of the nine alternative routes was conducted by an interdisciplinary project team consisting of the project director, the cable project engineer, the project communications director and two environmental siting and licensing specialists (id.). The Company stated that the process for ranking the alternative routes based on the Company's 14 routing criteria involved several steps: a paired analysis of each route against every other route for each of the evaluation criteria; weighting of evaluation criteria; and, finally, the application of weights to produce weighted paired analyses and a final ranking of routes based on environmental factors (id.). The Company stated that comparisons were based on actual counts, measurements or the consensus of the interdisciplinary team with respect to the impact or opportunity presented by a specific criterion (id.).

The Company stated that its environmental constraint criteria included: (1) parkland crossings (which could result in temporary construction impacts to parkland use);

34 The Company indicated that early consideration of a route along the MBTA Old Colony Railroad right-of-way ("ROW") ceased after the project team determined, and MBTA officials concurred, that the ROW would be too narrow to accommodate both the transit system and the electric cables for the proposed project (Exh. NEP-1, at 3-4).

35 The Company stated that it held over 100 meetings in Boston and Quincy with natural resource agencies, regulatory agencies, elected officials, city departments, private landowners, civic associations and the general public to solicit input on routing and permitting (Exh. NEP-1, at 3-9).

(2) waterway/waterbody crossings (which could result in a variety of potential construction impacts and permitting issues); (3) wetland/saltmarsh crossings (construction impacts to ecology and regulatory issues, with severity of impact based on linear distance of disturbance); (4) shellfish beds/tidelands crossings (possible temporary construction impacts, with severity of impact based on linear distance of disturbance); (5) crossings of an area of critical environmental concern (severity of impact based on linear distance of disturbance); (6) the number of proximate residential dwellings (temporary traffic, noise and accessibility issues); (7) the number of proximate business properties (potential temporary loss of revenue); (8) traffic impacts (disruption to traffic, with severity measured in vehicle miles, the product of traffic volumes times the length of a route in roadway, rounded to nearest 1,000 feet); (9) community acceptance (which was scored for each route based on total of values assigned to route segments using a range of one/"low" acceptance to five/"high" acceptance to reflect comments at public meetings); (10) street construction (re-opening of recently paved streets was considered undesirable); and (11) future development (likelihood of route/roadway usage by relocated traffic patterns as a result of existing and future civil projects in southeast Dorchester) (id. at 3-9 to 3-12).

The Company stated that its environmental opportunity criteria included: (1) use of highway/transit corridors, i.e., the length in feet of routing along major highways, away from local streets, residences and businesses; (2) use of off-street/private ROWs (impacts to general community limited, with benefit based on linear distance of route through the off-street/private ROW); and (3) use of preferred waterway crossing techniques (likelihood of use of a preferred crossing technique given the length of crossing required, with preference for bridges or horizontal directional drilling over jet plowing techniques, and preference for jet plowing over conventional cut and cover dredging) (id. at 3-12 to 3-13).

The Company stated that for each paired analysis, the route which had the lesser impact or greater opportunity received a score of "1", while the route with the greater impact or lesser opportunity received a score of "0" (id. at 3-13 to 3-14). Both routes received a "0" if their impact/opportunity was judged equivalent (id.). The Company indicated that a higher cumulative value signified a route which was more advantageous from an environmental standpoint with respect to siting the proposed electric cables (id.).

The Company stated that each member of its team of evaluators assigned weights from "1" (lowest) to "5" (highest) to each criterion to reflect the relative importance of the various criteria in the route selection process (id. at 3-14). The Company stated that the team discussed the initial assignment of weights, each evaluator made a second assignment of weights in light of the team's discussion, and a final average weight was then calculated for each criterion (id.).

The Company stated that it multiplied the total value of each constraint or opportunity from its unweighted paired analysis for each study route by the applicable weighting factor to derive a weighted score, and that the weighted scores of all criteria for each route were then summed to derive a total route score (id.). The Company indicated that a higher total score signified a route which was more appropriate for the proposed project from the perspective of limiting environmental impacts (id.). The Company indicated that, of the nine identified routes, Route D8 (score = 220.6) and Route D6 (score = 186.0) received the highest total scores while Route D2 (score = 90.6) received the lowest total score (id. at 3-17, 3-18).

The Company stated that it also developed a reliability criterion to compare alternatives with respect to (1) improvement of power quality, i.e., maintenance of required voltage, and (2) reduction in the frequency of interruptions (id. at 3-22). The Company indicated that outages would occur along the various route alternatives at essentially the same rate, but there would likely be some differences in the duration of outages depending on the route (id.). The Company indicated that repairing encased cables at a point of limited or no accessibility, for example at a segment of cable route involving a major thoroughfare, water crossing or railroad track, would extend repair time substantially (id. at 3-22 to 3-23). The Company noted that the nine evaluated alternative routes each had two to five segments which could potentially require lengthy repairs (id. at 3-23). The Company stated, however, that repair time for all routes would likely be comparable with the exception of Routes D3 and D4, which would involve underwater crossings of 3,750 feet and 9,750 feet, respectively (id.). The Company indicated that repairing cable failure at either of the two identified underwater crossings would require significantly more repair time and cost, both for keeping spare materials on hand and for repairs, than cable failure at other locations along any of the evaluated routes (id.). Thus, the Company asserted, the evaluated routes fell into one of two categories with respect to reliability: Routes D1, D2, and D5 through D9 would be comparable with respect to reliability, but Routes D3 and D4 would be less reliable due to the potential for longer repair times along those routes (id.).

To determine the cost of each facility alternative, the Company summed the estimated costs of materials, construction and engineering for the underground transmission facilities for each route (id. at 3-18 to 3-19).[36] The Company provided a cost summary of alternative routes as follows:

Route #	Route Name	Length (mi.)	Total Cost ($M)	Ranking
D1	Freeport-Hancock	2.8	$20.3	2
D2	Neponset-Hancock	2.8	$21.0	4
D3	Dorchester Bay-Squantum Pt.	2.9	$22.8	6
D4	Neponset River	2.6	$35.8	9
D5	Clayton-Squantum Pt.	3.7	$23.3	8
D6	Expressway-Hancock	2.6	$19.9	1
D7	Freeport-Squantum Pt.	3.6	$23.0	7
D8	Expressway-Squantum Pt.	3.3	$22.4	5
D9	Clayton-Expressway-Hancock	3.0	$20.6	3

36 The Company stated that its estimated costs of material, construction and engineering included: (1) preliminary design and permit application/acquisition; (2) excavation, including removal of pavement (where applicable) and backfill; (3) unusual installation techniques such as pipe jacking (tunneling), directional drilling or bridge attachment; (4) installation of manholes and conduit; (5) temporary and/or permanent pavement or other surface restoration, as applicable; (6) cost of cable material and installation, including splicing, terminations and testing; and (7) engineering, design, contract administration and documentation (Exh. NEP-1, at 3-18 to 3-19).

(id. at 3-18).

The Company stated that the cost of line losses and the cost of additions and modifications to the North Quincy and Dewar Street substations would be the same for all routes, as would the cost to upgrade BECo's existing underground transmission circuits to accommodate the proposed circuits (id.). The Company indicated that the construction costs at the North Quincy substation would total \$4.4 million; construction costs at the Dewar Street substation would total \$1.6 million; and costs for upgrading BECo's existing underground transmission circuits would total \$1.6 million (id. at 3-22).

The Company indicated that it considered the environmental, cost and reliability rankings of evaluated routes in selecting a primary and alternative route for its proposed project (id. at 3-23). The Company stated that with respect to environmental rankings, Route D8 was judged most compatible and Route D2 least compatible with the existing environmental setting (id.). Other routes were assigned relative rankings as a percent of the difference between the weighted scores for Routes D8 and D2 (id. at 3-23 to 3-24).

The Company stated that a similar analysis was undertaken for the cost comparison (id. at 3-24). First the most expensive (Route D4) and least expensive (Route D6) route options were identified (id.). Relative cost rankings were then assigned to the remaining routes as a percent of the difference between the cost of Route D4 and Route D6 (id.).

With respect to reliability, the Company ranked routes in two categories: Routes D3 and D4 were judged less reliable than other routes due to the length of their respective water crossings (id. at 3-23). The Company judged all other routes to be of similar reliability (id.).

The Company combined the environmental and cost ratios of its nine route options[37] and selected the option with the highest combined ratio (184.3), Route D8, as its primary route and the option with the second highest combined ratio (173.4), Route D6, as its alternative route (id. at 3-25). The Company stated that because the expected reliability of the primary and alternative routes was the same as, or better than, the expected reliability of the other seven

[37] The combined environmental and cost ratios of the nine evaluated route options ranged from a high of 184.3 to a low of 45.4 (Exh. NEP-1, at 3-25).

route options, no further consideration of reliability in the route selection process was necessary (id.).

b. Analysis

NEPCo has developed a set of criteria for identifying and evaluating route options that addresses natural resource issues, land use issues, human environmental issues, cost and reliability -- types of criteria that the Siting Board has found to be appropriate for the siting of transmission lines and related facilities. See 1997 BECo Decision, EFSB 96-1, at 68; 1997 ComElec Decision, EFSB 96-6, at 53; New England Power Company, 4 DOMSB 109, 167 (1995) ("1995 NEPCo Decision").

To identify route options for further evaluation, the Company first identified an area that would encompass all viable siting options given the limitations imposed by the location of the interconnecting North Quincy and Dewar Street substations. The Company used four conceptual routes within the identified area as a starting point for discussions with regulatory agency staff, elected officials and neighborhood representatives. These discussions resulted in the development of nine routing alternatives for comparison. The Company developed a comprehensive list of environmental constraints and opportunities to evaluate these nine routing alternatives. The weighting of specific environmental constraint and opportunity factors appropriately reflects their relative significance; in particular, the desirability of siting transmission lines within existing corridors where possible is appropriately stressed, as is the need to route the proposed facilities to minimize disruptive construction in residential and commercial areas. The Company also ranked its identified alternatives with respect to cost and reliability.

For each of the identified alternatives, the Company calculated environmental ratio scores based on their weighted environmental scores and cost ratio scores based on estimated costs. The Company used the environmental and cost ratio scores for the identified alternatives, along with their reliability rankings, to balance the environmental impacts, reliability and cost of the nine evaluated route options for its proposed facilities.[38] Thus, the Company has provided a comprehensive, quantitative method to compare identified alternatives on the basis of environmental impacts, cost and reliability.

Based on the foregoing, the Siting Board finds that the Company has developed a reasonable set of criteria for identifying and evaluating facility alternatives. The Siting Board also finds that the Company has applied its site selection criteria consistently and appropriately, and in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to the proposed project.

Accordingly, the Siting Board finds that the Company has developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the proposed project in a manner which ensures that it has not overlooked or eliminated any siting options which are clearly superior to the proposed project.

3. Geographic Diversity

NEPCo considered nine geographically diverse transmission line routes between BECo's Dewar Street substation and the North Quincy substation to which the Company proposes modifications to accommodate its proposed transmission lines. Although each identified route between the existing substation sites overlaps a segment of at least one other route, each identified route is clearly distinct: each offers a unique set of environmental, reliability and cost constraints and advantages within the area designated by the Company as encompassing all viable siting options for its proposed transmission lines. Consequently, the

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[38] In summing the environmental ratio scores and cost ratio scores to derive combined ratio scores, the Company effectively attributed equal weight to (1) the net environmental advantage of the route with the highest environmental score over that with the lowest environmental score and (2) the cost advantage of the least-cost route over the highest-cost route. In other words, the range of net environmental differences was equated to the $15.9 million range of costs. The Siting Board accepts that equal weighting of the range of environmental differences and range of cost differences was reasonable, based on the record in this review.

Siting Board finds that the Company has identified a range of practical transmission line routes with some measure of geographic diversity.

4. Conclusions on the Site Selection Process

The Siting Board has found that the Company developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the proposed project in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposed project. In addition, the Siting Board has found that the Company has identified a range of practical transmission line routes with some measure of geographic diversity. Consequently, the Siting Board finds that NEPCo has demonstrated that it examined a reasonable range of practical facility siting alternatives.

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

1. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring a reliable energy supply. To determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed project site for the facility is superior to the noticed alternatives on the basis of balancing cost, environmental impact, and reliability of supply. 1997 BECo Decision, EFSB 96-1, at 72; 1997 ComElec Decision, EFSB 96-6, at 60; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

An assessment of all impacts of a facility is necessary to determine whether an appropriate balance is achieved both among conflicting environmental concerns as well as among environmental impacts, cost, and reliability. 1997 BECo Decision, EFSB 96-1, at 72; 1997 ComElec Decision, EFSB 96-6, at 60; Eastern Energy Corporation, 22 DOMSC at 188, 334, 336 (1991) ("EEC Decision"). A facility which achieves that appropriate balance thereby meets the Siting Board's statutory requirement to minimize environmental impacts at the lowest possible cost. 1997 BECo Decision, EFSB 96-1, at 287; 1997 ComElec Decision, EFSB 96-6, at 60; EEC Decision, 22 DOMSC at 334, 336.

An overall assessment of the impacts of a facility on the environment, rather than a mere checklist of a facility's compliance with regulatory standards of other government agencies, is consistent with the statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. 1997 BECo Decision, EFSB 96-1, at 73; 1997 ComElec Decision, EFSB 96-6, at 60; EEC Decision, 22 DOMSC at 334, 336. The Siting Board previously has found that compliance with other agencies' standards clearly does not establish that a proposed facility's environmental impacts have been minimized. Id. Furthermore, the levels of environmental control that the project proponent must achieve cannot be set forth in advance in terms of quantitative or other specific criteria, but instead, must depend on the particular environmental, cost and reliability trade-offs that arise in respective facility proposals. 1997 BECo Decision, EFSB 96-1, at 73; 1997 ComElec Decision, EFSB 96-6, at 60-61; EEC Decision, 22 DOMSC at 334-335.

The Siting Board recognizes that an evaluation of the environmental, cost and reliability trade-offs associated with a particular review must be clearly described and consistently applied from one case to the next. Therefore, in order to determine if a project proponent has achieved the appropriate balance among environmental impacts and among environmental impacts, cost and reliability, the Siting Board must first determine if the petitioner has provided sufficient information regarding environmental impacts and potential mitigation measures in order to make such a determination. 1997 BECo Decision, EFSB 96-1, at 73; 1997 ComElec Decision, EFSB 96-6, at 61; Boston Edison Company (Phase II), 1 DOMSB 1, at 39-40 (1993). The Siting Board can then determine whether environmental impacts would be minimized. Similarly, the Siting Board must find that the project proponent has provided sufficient cost information in order to determine if the appropriate balance among environmental impacts, costs and reliability would be achieved. 1997 BECo Decision, EFSB 96-1, at 73; 1997 ComElec Decision, EFSB 96-6, at 61; Boston Edison Company (Phase II), 1 DOMSB 1, at 40 (1993).

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

2. Analysis of the Proposed Facilities Along the Primary Route

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

In this section, the Siting Board evaluates the environmental impacts of the proposed facilities along the primary route and the proposed mitigation for such impacts, and any options for additional mitigation. As part of its evaluation, the Siting Board first addresses whether the petitioner has provided sufficient information for the Siting Board to determine: (1) whether environmental impacts of the proposed facilities would be minimized; and (2) whether the proposed facilities achieve the appropriate balance among environmental impacts and among environmental impacts, cost and reliability.[39] The Siting Board then addresses whether the environmental impacts of the proposed facilities along the primary route would be minimized.

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[39] The Siting Board notes that in the current proceeding there are no differential reliability issues to be balanced against environmental and cost issues (Exh. NEP-1, at 3-47).

(i) Water Resources

The Company indicated that certain portions of the primary route, including Squantum Point, the mouth of the Neponset River, and a section along Commander Shea Boulevard, were within the boundaries of the Neponset River Area of Critical Environmental Concern ("Neponset River ACEC") (Exh. NEP-1, at 3-53). The Company asserted, however, that any impacts to water resources[40] along these segments of the primary route would be insignificant and temporary, as discussed below (Company Brief at 23). The Company stated that it anticipated restoring to their pre-existing condition any resources of the Neponset River ACEC disturbed by construction along the primary route, except as otherwise directed by the MDC and other permitting agencies (Exh. NEP-1, at 3-55).

The Company stated that the primary route would cross the estuarine portion of the Neponset River between Commercial Point and Squantum Point on the Boston and Quincy sides of the river, respectively (id. at 3-48 to 3-49). The primary route would cross the navigational channel of the river and a portion of Buckley's Bar in Quincy (id.). The Company indicated that shellfish beds located on Buckley's Bar are highly productive but contaminated (id.).[41,42]

To minimize the impacts to Buckley's Bar and other Neponset River resources, the Company stated that it would use HDD along the primary route to install the proposed

40 Impacts to water resources include impacts to wetlands, surface water, groundwater and wells, as applicable.

41 Shellfish harvest is prohibited in the Neponset River due to high fecal material concentrations (Exh. NEP-1, at 3-48).

42 The water quality of the estuarine portion of the Neponset River is classified as SB, i.e., suitable for the following use designations: aquatic life, fish consumption, primary and secondary contact recreation, aesthetics, agricultural and industrial uses, and shellfish harvesting (Exh. NEP-1, at 3-48). However, a 1995 study reported that Neponset River water quality did not meet standards for the SB designation (id.). Specifically, the study indicated that the water quality of the Neponset River failed to fulfill standards for primary contact recreation, aquatic life and aesthetics and only partially fulfilled standards for secondary contact recreation (fishing, boating, and incidental water contact)(id.).

transmission lines across the Neponset River (id. at 3-49). The Company explained that to effect the crossing, a drilling rig would tunnel 15 to 40 feet beneath the river bottom (id.; Exh. HO-E-1). The Company anticipated no sediment disruption or water column impact in association with its use of HDD (Exh. HO-E-1). The Company stated that a NEPCo inspector would be on-site during the drilling process and that a drilling mud recovery plan would assure preservation of the river's biotic resources in the unlikely event of a drilling blow-out (id.; Exh. NEP-1, at 3-49).

The Company stated that crossing of the Neponset River and construction along Commander Shea Boulevard would result in limited construction in the 200-foot Riverfront Area ("Riverfront Area"), recently designated a resource area under the Rivers Protection Act ("RPA") (Exhs. NEP-1, at 3-49; HO-E-4). The Company indicated that it satisfied the two-tier test for work in the Riverfront Area, first, by conducting the alternatives assessment in the instant filing and, second, by ensuring that the proposed facility would have no significant adverse impact in the Riverfront Area based on the proposed restoration of contours and vegetation and the proposed use of HDD for the Neponset River crossing (Exhs. NEP-1, at 3-49; HO-E-4). The Company asserted that impacts to the Neponset River and the Riverfront Area related to construction of the proposed facilities along the primary route would be temporary, and that no shellfish habitat would be lost due to construction (Exhs. NEP-1, at 3-49; HO-E-4).

The Company indicated that it identified one bordering vegetated wetland and one isolated wetland north of Victory Road common to both the primary and alternative routes. The Company stated that along either route, the proposed facilities would skirt a bordering vegetated wetland ("BVW"), and an isolated wetland (Exh. HO-E-5). The Company also stated that the proposed transmission lines would traverse about 200 feet of buffer zone of the BVW, and noted that the isolated wetland has no regulatory buffer zone (id.). There is no anticipated disturbance to wetlands south of Victory Road along the primary route (id.). Buffer zone would be crossed for about 3,150 linear feet along Commander Shea Boulevard, not including routing through Squantum Point Park (id.). The Company indicated that its primary route through Squantum Point Park, finalized in conjunction with the MDC, was designed to avoid crossing wetlands (id.; Exhs. NEP-1, at 3-52, 3-55; HO-RR-8; HO-RR-11).[43]

The record demonstrates that the Company plans to use HDD to cross the Neponset River and to install its proposed transmission lines in a manner that avoids impacts to other water resources, including wetlands. The record also demonstrates that the Company anticipates restoring to their pre-existing condition any resources of the Neponset River ACEC disturbed by construction along the primary route, including resources of the Riverfront Area, the Neponset River and Squantum Point Park, and wetland resources. Based on its analysis of the record, the Siting Board concludes that there would be no permanent impact and only minimal temporary impacts to water resources resulting from construction of the proposed facilities along the primary route.

Accordingly, the Siting Board finds that with implementation of the proposed mitigation measures, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to water resources.

(ii) Land Resources

The Company indicated that some brush, mostly smooth sumac, would be cut in the vicinity of the IBEW buildings along Freeport Street in Boston; some small trees and brush would be cut for construction on Squantum Point; several trees would be removed for the substation expansion at the Dewar Street substation site; and some landscaping and a few landscape trees would be removed for the substation expansion at the North Quincy substation (Exh. HO-E-14). The Company anticipated no additional tree removals for operation of the proposed facilities, and planned no use of herbicides during the clearing or future maintenance

43 The Company indicated that the primary route would follow the northern edge of an old abandoned airstrip through Squantum Point Park, and would thereafter follow the Boston Scientific property line to Commander Shea Boulevard (Exhs. NEP-1, at 3-53 to 3-54; HO-RR-8; HO-RR-11). The Company's proposed route through Squantum Point Park would involve no disturbance to wetlands or associated buffer zones (Exhs. HO-RR-8; HO-RR-11).

of the primary route (id.). The Company stated that after construction, both the Dewar Street and North Quincy substation sites would be landscaped with trees and shrubs, and that revegetation would take place at Squantum Point as directed by the MDC (id.). Finally, the Company made a commitment to maintain a constant level of vegetation along the route of the proposed facilities, including at the Dewar Street and North Quincy substations, before and after construction (Tr. 1, at 73 to 74).

The Company indicated that the potential for soil erosion is low along the primary route due to the generally flat terrain of the area and stated that it would control soil erosion through final grading of topsoil, heavy mulching of soil with hay or wood chips, and stockpiling of trench spoil off-site rather than along streets or open space associated with the primary route (Exh. HO-E-15). The Company also stated that it would use silt fences and hay bales when constructing in the buffer zones of wetlands (id.).

The Company indicated that a walkover of the primary route and a search of existing MDEP and other data sources produced no evidence of contaminated soils that would preclude construction of the proposed facilities along the primary route (Exh. HO-E-16). The Company stated that a Licensed Site Professional ("LSP") would determine procedures for the handling of contaminated soil encountered during construction, if any, including disposal at an approved off-site landfill or as backfill in the construction trench, as appropriate (id.).

No federally-protected or proposed endangered or threatened species is associated with the primary route (Exh. HO-E-20). In addition, a site reconnaissance by the Massachusetts Natural Heritage and Endangered Species Program ("MNHESP") indicated that no endangered species breeding habitat would be affected by the proposed cable installation (id.).[44] The Company indicated its commitment to work with the MNHESP and the MDC to ensure that impacts to bird habitat at Squantum Point Park would be minimized and temporary (Tr. 1, at 79 to 80).

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44 The analysis by the MNHESP assumes the restoration to natural habitat of any area of Squantum Point which would be impacted by construction (Exh. HO-E-20).

The record demonstrates that, along or in the vicinity of the primary route, there would be minimal clearing of trees and vegetation associated with the proposed project and that the Company has made a good faith commitment to replace trees and vegetation removed during construction; that loss of soil would be insignificant and that the Company plans measures to minimize soil erosion and to dispose properly of contaminated soils, if any; and that no known rare or endangered species, or endangered species habitat, including breeding habitat, would be adversely affected by the proposed construction.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land resources.

(iii) Land Use

In this Section, the Siting Board reviews the impact of the construction and maintenance of the proposed facilities along the primary route with respect to land use, zoning, traffic, safety and noise.

The Company submitted a description and map of land uses along the primary route based on data from the Massachusetts Geographic Information Systems ("MGIS") office (Exh. NEP-1, at 3-56 to 3-57). Land use tracts along the primary route include areas of public utility, industrial, commercial and business use, vacant land bordering a major highway, several smaller roadways, recreational facilities (a yacht club), public parkland, and residential apartments (id.).

The Company asserted that construction and operation of the proposed facilities would cause minimal disruption of existing land use (id. at 3-58, 3-65 to 3-66). Active business, commerce, and residential areas would be avoided to the maximum extent practicable, and construction in major thoroughfares would be limited to two highway crossings (Morrissey Boulevard and Victory Road) (id.). The Company stated that access during construction to business and recreational operations along the primary route would be maintained, as would access to residential locations (id.).

The Company stated that the portion of the primary route in Boston is located within industrial and light manufacturing districts along the Southeast Expressway and a waterfront service district at Commercial Point (id. at 3-55 to 3-56). In the City of Quincy, the initial segment of the route is within a "planned unit development" zone on Squantum Point, owned by the MDC (id.).[45] The majority of the primary route in Quincy is located in business districts adjacent to Commander Shea Boulevard (id.). A short segment lies in an industrial district (id.). The final 1,300 linear feet in Commander Shea Boulevard is adjacent to a residential district and a city park which is classified as an open space district (id.).[46]

The Company stated that neither the City of Boston Zoning Code nor the City of Quincy Zoning Ordinance specifically addresses underground facilities as an allowed use (id.; Exh. HO-E-9S). In discussions with the Company, however, the Boston Redevelopment Authority and the Quincy Building Inspector indicated that an underground cable is not a regulated use, and that construction and operation of the proposed underground cable therefore would not conflict with zoning regulations (Exhs. NEP-1, at 3-56; HO-E-10).

The Company stated that its conversations with the Quincy Building Department indicated that expanding the North Quincy substation as proposed was allowed within the business district where it was located, but would require a special permit from the City of Quincy or a zoning exemption from the Department (Exh. HO-E-12). The Company indicated that it had filed a petition (D.P.U. 97-99) with the Department for such a zoning exemption (Exh. HO-E-41). The Company also indicated that expansion of the Dewar Street substation was allowed under the City of Boston Zoning Code in the Industrial District where it was located (Exhs. NEP-1, at 3-56; HO-E-11S).

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45 The referenced planned unit development is an area which the MDC is in the process of developing into a park, its designated use (see Section III.C.a.(1), above).

46 The Company indicated that the primary route for its proposed facilities would pass through three Boston zoning districts, General Manufacturing (3,650 feet, 21 percent), Light Manufacturing (1,000 feet, six percent), and Waterfront Industry (1,100 feet, six percent) as well as three zoning districts in Quincy, Planned Unit Development (3,400 feet, 20 percent), General Business (6,050 feet, 35 percent) and Multifamily/Low Density Residential (2,050 feet, 12 percent) (Exh. HO-RR-9).

The Company provided a letter from the Massachusetts Historical Commission ("MHC") which indicated that the MHC anticipated no impact along the primary route to any significant historic or archaeological resources (Exh. HO-E-22, Att. 1).

The Company stated that the primary route would avoid major roadways for most of its length (Exh. NEP-1, at 3-67 to 3-68). Between Dewar Street substation and Victory Road, approximately 0.8 miles, the primary route would be constructed in open space adjacent to the MBTA tracks and the bottom of the slope adjacent to the Southeast Expressway (id.). Traffic impacts along this segment of the primary route would be limited to disruption caused by moving equipment and materials into and out of construction areas (id.). The Company indicated that the flow of traffic at the Morrissey Boulevard and Freeport Street intersection and off the Southeast Expressway at Victory Road would be maintained at all times during the construction period (id.). The Company estimated installation time for the proposed conduits between the Dewar Street substation and Victory Road at four to six weeks (id.).

The Company indicated that the proposed transmission lines would be installed along Victory Road for a length of approximately 1000 feet and along Commander Shea Boulevard in Quincy for a length of nearly one mile (id. at 3-26). The Company stated that traffic volumes on Victory Road, including the off-ramp to Victory Road from the Southeast Expressway, and on Commander Shea Boulevard were relatively low -- 4500 and 4000 vehicles per day, respectively -- and noted that two-way traffic would be maintained along Commander Shea Boulevard during construction (id. at 3-67 to 3-68). To minimize traffic impacts the Company would: undertake construction at off-peak hours to the extent practicable; maintain traffic access by use of steel plates; use traffic control officers and signage; drill or bore under major road crossings as feasible; and keep the community informed of progress and construction timetables (id.). The Company stated that the proposed transmission lines would be installed along Victory Road and along Commander Shea Boulevard in Quincy, and noted that two-way traffic would be maintained along Commander Shea Boulevard (id.).

The Company indicated that installation of the proposed conduits in Victory Road would require one to two weeks, and that manhole installation and directional drilling in Victory

Road would require an additional week to two weeks (id.). Installation of the proposed facilities in Commander Shea Boulevard would require four to five weeks (id.).

The Company stated that in paved areas, roadways would receive temporary pavement immediately after backfill, with permanent paving in conformance with the rules, regulations and policies of the City of Boston Department of Public Works ("DPW") and the City of Quincy DPW (Exh. HO-E-17). The Company has committed to curb-to-curb paving of Commander Shea Boulevard in Quincy and will oversee paving operations there and elsewhere along the route of the proposed facilities as required by the Cities of Boston and Quincy (id.). If the City of Boston chooses to require payment in lieu of paving, the City of Boston will oversee the paving at a later date (id.).

The Company guaranteed access for fire and safety equipment at all times (Exh. NEP-1, at 3-66).

The Company stated that all substation and cable construction, maintenance and operations work would be performed in accordance with relevant OSHA standards and the safety policy of the NEES companies and BECo, as applicable (Exh. HO-E-30). In addition, the Company indicated that safety impacts would be minimized by measures including, but not limited to, maintenance of a fence at least seven feet high around the substation sites during and following construction, the use of police details during construction occurring in a traveled way, and the required development and use by contractors of a safety plan approved by the Company (id.).

The Company indicated that normal construction noise would be associated with the installation of the proposed transmission lines along the primary route, but would typically be confined to the hours of 7:30 a.m. to 4:30 p.m., Monday through Friday (Exhs. NEP-1, at 3-64; HO-E-27). The Company stated that night work would occur for only two reasons: to minimize impacts when installing the proposed transmission lines across heavily traveled roadways, and to carry out construction activities such as cable splicing and horizontal directional drilling which require round-the-clock operations (Exh. HO-E-26). With respect to such round-the-clock operations, the Company indicated that cable splicing, which might take place in the vicinity of residences, would generate very little noise, and that nearby residences would be notified of the splicing schedule (id.).

The Company anticipated that Dewar Street substation construction would take place over a period of about six months and North Quincy substation construction would take place over an 18-month period, but that the work would not be continuous at either substation (Exh. HO-E-28). Noise sources specific to the two proposed substations would include installation of a heat exchanger and pile foundations at the Dewar Street substation and pile foundations at the North Quincy substation (id.; Exh. HO-E-29). The Company provided documentation showing that projected operating noise levels at the Dewar Street substation with the proposed heat exchanger installed would not exceed existing nighttime ambient L_{90} noise levels at the nearest property line and at the property line closest to the nearest residence (Exh. HO-E-29). With respect to pile installation, the Company indicated that pile driving would occur over a three to four week period at Dewar Street substation and over a four to six week period at the North Quincy substation (id.). The Company stated that it would limit pile driving to Mondays through Fridays, starting no earlier than 8:00 a.m. and ending no later than 4:30 p.m., to the extent possible (Tr. 2, at 11, 40).[47]

With respect to land use impacts, an interested person in the instant proceeding, Mr. Charles Tevnan, questioned whether the public would have reasonable access to the boat ramp, fishing pier, and parking lot located in Boston Gas Company's Rainbow Park at the Neponset River end of Victory Road (Tevnan Reply Brief at 4). In addition, Mr. Tevnan raised the issue of potential noise impacts to residents in the vicinity of the Dewar Street substation (id. at 2).

The record demonstrates that the land use impacts of the construction of the proposed underground transmission lines would be temporary and minimized along the preferred route. Specifically, the Company will take steps to limit disruption to residences and businesses and

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47 The Company indicated that it might be necessary to plan outages to drive piles in areas where live underground cables are located. The Company would coordinate the timing and extent of such outages based on system load and flows. In the event that weekday outages could not be arranged, pile-driving would take place during weekend hours (Tr. 2, at 40).

ensure access to recreational activities such as boating and fishing, repave or ensure repaving of streets disturbed by construction, and otherwise ensure the restoration of the primary route to its original condition to the extent possible. The record further demonstrates that the Company will follow all OSHA and other regulations applicable to construction and operation of the proposed facilities, and maintain the flow of traffic and passage of emergency vehicles.

In addition, the record demonstrates that noise impacts associated with construction will be minimized by limiting such noise to normal working hours, Monday through Friday, to the extent possible, and that the operating noise of the proposed heat exchanger will not increase the noise level in the vicinity of the Dewar Street substation.

Accordingly, the Siting Board finds that, with the implementation of all proposed mitigation, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land use.

(iv) Visual

In this Section, the Siting Board reviews the visual impacts of establishing the proposed facilities along the primary route.

The Company asserted that no visual impact would result from installation of the proposed underground transmission lines or associated manholes except on a temporary basis during the construction period (Exh. NEP-1, at 3-63). The Company stated that manholes for the proposed underground transmission lines would be flush mounted on the ground and would not be visible except in the immediate vicinity of the manholes (id.).

The Company asserted that the two substations to be expanded, the Dewar Street and North Quincy substations, were not in visually sensitive areas and that contemplated changes would be consistent with existing land uses (id. at 3-64). With respect to the Dewar Street substation, the Company provided illustrations of the substation with surrounding land uses and landscaping, both before and after the proposed expansion (Exh. HO-S-2, Att. 12, at 5, 6). The illustrations indicated that the closest residential buildings were located at a distance of 400 to 500 feet from the existing substation facilities, opposite the entrance to the substation property, and that the Company planned to install landscaping at the property entrance where none currently exists (id.; Exh. NEP-1, at 1-2). In addition, expansion of substation facilities would occur on the side of the substation property farthest from abutting residential land use (Exh. HO-S-2, Att. 12, at 5, 6).

With respect to the North Quincy substation, the Company stated that the proposed expansion would result in a three-fold increase in the footprint of the buildings and electrical switchgear, but would not extend beyond the existing fenceline of the substation site (Exh. NEP-1, at 3-64). The Company also would extend an existing textured concrete wall to screen most substation yard structures from view (id.). The Company submitted initial landscaping plans designed to minimize visual impacts on residences abutting the North Quincy substation and provided details of meetings held by the Company with owners of property abutting the substation to refine the proposed landscaping (Exhs. HO-E-24; HO-E-25; HO-E-48).

With respect to visual impacts, Mr. Tevnan argued that the Company erred in describing the vicinity of the Dewar Street substation as not visually sensitive (Tevnan Reply Brief at 2). Mr. Tevnan also contended that the plantings proposed for the entrance gate of the substation would not adequately screen the proposed substation expansion from the nearby Savin Hill Apartments (id. at 2 to 3).

The record demonstrates that visual impacts of the proposed underground transmission lines along the primary route would be temporary and limited to the construction period. The record also demonstrates that the proposed changes at the North Quincy and Dewar Street substations would expand the current substation facilities within their current site boundaries, and that the proposed expanded facilities would be screened to the extent practicable from surrounding land uses. In the case of the North Quincy substation, the Company has worked with abutting property owners to ensure adequate vegetative screening. At the Dewar Street substation, the Company's planned landscaping at the entrance of the substation property would soften and screen views from the closest residence, the Savin Hill apartment complex, 400 to 500 feet away. In addition, the visible expansion of the Dewar Street substation facilities would occur only on the side of the substation property farthest from abutting residential land use.

Accordingly, the Siting Board finds that, with the proposed mitigation relative to the design and screening of the proposed facilities, the environmental impacts of the proposed facilities along the primary route would be minimized with respect to visual impacts.

(v) Magnetic Field Levels

The Company calculated that magnetic fields generated by the proposed transmission lines operating at maximum load (i.e., during a common mode outage) would be 1.9 mG at one meter above the ground over the center of the cables (Exhs. NEP-1, at 3-45; HO-A-18). The corresponding magnetic field strength at ten feet away from the centerline of the proposed cables would be 0.7 mG (id.).

To simulate the effect of the proposed facilities on existing magnetic field strength, the Company provided magnetic field levels for the Dewar Street substation given three scenarios, the first, under conditions of normal operation, in which full Quincy load is supplied from BECo's Edgar facility, the second in which North Quincy load is supplied via the Dewar Street substation because two cable sections between Field Street and North Quincy substations are out of service, and the third in which full Quincy load is supplied via the Dewar Street substation because key transmission lines in the BECo system are out of service (Exh. HO-E-32).

The Company anticipated no change in the existing magnetic field levels around the perimeter of the Dewar Street substation under normal operating conditions (Exh. HO-E-34).[48] The Company calculated the present maximum operating magnetic fields around the four sides of the North Quincy substation at 0.1 mG (on the side closest to the MBTA rail lines), 2 mG (on the residential property side), 12.5 mG (on the M & P Partners side) and 19 mG (on the SCI building parking lot side of the fence) (Exh. HO-E-32). The Company anticipated that, with cable service failure between the Field Street and North Quincy substations, magnetic field levels would remain at 2 mG on the residential property side of the substation and

[48] The Company explained that with the existing cables from BECo's Edgar facility in operation, the proposed new transmission lines would be energized but would not carry any load (Exh. HO-E-34).

increase to between 11 and 23 mG on the remaining three sides of the substation property for the duration of the outage (id.). Under the Company's worst case scenario, in which the entire load of the City of Quincy would be supplied via the Dewar Street substation, magnetic field levels would remain at 2 mG on the residential property side of the substation and increase to between 28 and 47 mG on the remaining three sides for the duration of the outage (id.).[49,50]

The Company also provided magnetic field levels for the Dewar Street substation given two scenarios, the first, under conditions of normal operation, in which full Quincy load is supplied from BECo's Edgar facility, and the second in which full Quincy load is supplied via the Dewar Street substation because key transmission lines in the BECo system are out of service (Exh. HO-E-33). As at the North Quincy substation, the Company anticipated no change in the existing magnetic fields around the perimeter of the Dewar Street substation under normal operating conditions (Exh. HO-E-34). Under the second scenario, the Company anticipated an increase of 48 mG on the east side of the substation closest to the MBTA rail line and 28 mG on the south side of the substation for the duration of the outage (id.; Exh. NEP-1, at 3-26, 3-32).

In a previous review of proposed transmission line facilities, the Siting Board accepted edge-of-ROW levels of 85 mG for the magnetic field. Massachusetts Electric Company/New England Power Company, 13 DOMSC 119, 228-242 (1985) ("1985 MECo/NEPCo Decision"). The Siting Board has also applied these edge-of-ROW levels in subsequent reviews of facilities which included 115-kV transmission lines. See, 1997 ComElec Decision, EFSB 96-6, at 73; Norwood Decision, EFSB 96-2, at 33; MASSPOWER, Inc., 20 DOMSC 301, 401-403 (1990). Here, the magnetic field levels, particularly along the primary transmission line route, but also in the vicinity of the North Quincy and Dewar Street substations, would be unaffected by the proposed project under normal operating conditions

49 The Company indicated that its worst case scenario represents an unlikely contingency (Tr. 2, at 52).

50 The Company's expert witness indicated that readings of magnetic field strength from substation transformers typically diminish quickly with distance from the source of the measured magnetic fields (Tr. 2, at 57).

and would remain far below the levels found acceptable in the 1985 MECo/NEPCo Decision, even assuming the Company's worst case scenario, i.e., supply of full load for the City of Quincy via the Dewar Street substation.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to magnetic field impacts.

(vi) Conclusions on Environmental Impacts

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

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

Accordingly, the Siting Board finds that, with the implementation of proposed mitigation and compliance with all applicable local, state, and federal requirements, the environmental impacts of the proposed facilities along the primary route would be minimized. In Section III.C.3.c, below, the Siting Board addresses whether an appropriate balance among environmental impacts and among cost, reliability and environmental impacts would be achieved.

b. Cost of the Proposed Facilities Along the Primary Route

The Company estimated the total cost for installation of the proposed transmission lines along the primary route at $14,800,000 (in 1997 dollars) broken down into six categories, as follows: construction, $6,200,000; materials, $3,900,000; engineering, $1,900,000; permitting $800,000; contingencies, $1,800,000; and right-of-way acquisition, $200,000 (Exh. HO-C-1). The Company indicated that it derived material costs from estimates provided by various material suppliers; construction costs -- modified by projected labor equipment rates for 1999 -- from the Company's experience on recent, similar projects and in consultation with outside contractors; and engineering and permitting costs from the estimated hours required for project completion plus contracted and estimated costs of engineering consultants (id.). Overhead costs, including interest during construction, supervision, payroll taxes and insurance were assigned to various cost categories as appropriate (id.). Annual cost of operation and maintenance for the proposed transmission lines along the primary route was estimated at $60,000 to $70,000 (Exh. HO-C-2).

The Company estimated the total cost for the proposed expansion of the Dewar Street substation at $1,600,000 (in 1997 dollars), as follows: construction $570,000; materials, $360,000; engineering, $500,000; permitting, $25,000; and contingencies, $145,000 (Exh. HO-RR-15). The estimated total cost of the proposed heat exchangers and related work on the K Street to Dewar Street 115 kV pipe type cables was $1,600,000, broken down into four categories as follows: construction, $200,000; materials, $1,200,000; engineering, $100,000; and contingencies, $100,000 (id.).

The Company submitted an estimated total cost for the proposed expansion of the North Quincy substation of $4,400,000 (in 1997 dollars), broken down into five categories: construction, $1,900,000; materials, $1,200,000; engineering, $500,000; permitting $400,000; and contingencies, $400,000 (id.).

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

c. Conclusions

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

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

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

3. Analysis of the Proposed Facilities Along the Alternative Route

a. Environmental Impacts of the Proposed Facilities Along the Alternative Route and Comparison

In this Section, the Siting Board evaluates the environmental impacts of the proposed facilities under the alternative route. First, as part of its evaluation, the Siting Board addresses whether the petitioner has provided sufficient information regarding the alternative route for the Siting Board to determine whether the environmental impacts of the proposed facilities would be minimized, and whether the proposed facilities would achieve the appropriate balance among environmental impacts and between cost and environmental impacts. If necessary for its review, the Siting Board separately addresses whether the environmental impacts of the proposed facilities along the alternative route would be minimized, with potential mitigation. Finally, in order to determine a best route, the Siting Board compares the environmental impacts of the primary route to the environmental impacts of the alternative route.

(i) Water Resources

The Company indicated that, like the primary route, the alternative route crosses the Neponset River, but further upstream at the Neponset River Bridge (Exh. NEP-1, at 3-52). The Company indicated that it would use an empty utility bay beneath the Neponset River Bridge to install its proposed transmission lines across the Neponset River (id.). The Company stated that using this bridge structure for the cable crossing would result in no impact to Neponset River sediments, water quality or biota, or on the Riverfront Area (id.). The Company noted that although trenching would be required near or within the 200-foot Riverfront Area where the cable meets surface roads in Quincy, the cable trench area would be restored to pre-existing conditions (id.).

The Company stated that the alternative route would pass the same isolated wetlands as the primary route from the MBTA tracks to Victory Road, and that it would pass through one more isolated wetland just south of the Victory Road and Freeport Street intersection for about 130 feet (Exh. HO-E-5). This would result in disturbance to about 3900 more square feet of wetland area, assuming a 30-foot construction easement, but no impacts to wetland buffer zone because the wetland is isolated (id.). The Company stated that the disturbed area would be restored to its pre-construction condition and that no permanent impacts to wetlands were anticipated (Exh. NEP-1, at 3-52).

In comparing the water resource impacts of the proposed facilities along the primary and alternative routes, the Company made three assertions: first, that the primary and alternative routes would be comparable with respect to impacts to the Neponset River, but that by keeping the Neponset River Bridge utility bay open, the primary route would potentially avoid impacts to the river from future projects; second, that the primary route would be preferable to the alternative route with respect to wetlands since it would cross a slightly lesser length of wetland area than the alternative route; and third, that the alternative route would not infringe upon the Neponset River ACEC and would therefore be slightly preferable with respect to impacts to Neponset River ACEC water resources (id. at 3-50, 3-52, 3-55).

The record demonstrates that the primary route would result in fewer impacts to wetlands than the alternative route. In addition, use of HDD along the primary route minimizes impacts to Neponset River resources. The alternative route also minimizes impacts to Neponset River resources, but would require use of limited remaining utility bay space in the Neponset River Bridge.

While the primary route, but not the alternative route, passes through the Neponset River ACEC, the primary route avoids water resource impacts within the Neponset River ACEC by passing under Buckley's Bar, along the wetlands-free edge of an abandoned airstrip in Squantum Point Park, and in the pavement of Commander Shea Boulevard until that roadway leaves the ACEC. Thus, the primary route offers benefits over the alternative route with respect to wetlands impacts and is comparable to the alternative route with respect to surface water resources impacts. The primary route also provides a potential long-term benefit for surface water impacts by leaving the Neponset River Bridge utility bay open for any future projects which must cross the Neponset River.

Accordingly, the Siting Board finds that the primary route is preferable to the alternative route with respect to impacts to water resources.

(ii) Land Resources

The Company indicated that construction of the proposed facilities along the alternative route would require clearing of trees and other vegetation in a number of the same locations required along the primary route, including in the vicinity of the Freeport Street IBEW buildings, and at the North Quincy and Dewar Street substations (Exh. HO-E-14). Mitigation and restoration of impacts to trees and vegetation at the substations and along Freeport Street along the alternative route and primary route would be comparable (id.). The alternative route would involve no clearing of trees and other vegetation at Squantum Point, but might require removal of a few shrubs in the area of Neponset Circle (id.). The Company anticipated no removal of trees or vegetation after construction of its proposed facilities along the alternative route, and stated that no herbicides would be used (id.).

The Company indicated that due to its flat terrain, the potential for soil erosion along the alternative route was minimal and comparable to that along the primary route (Exh. HO-E-15). The Company also stated that techniques for mitigating soil loss along both routes would be comparable (id.).

The Company indicated that a walkover of the alternative route and a search of existing MDEP and other data sources produced no evidence of contaminated soils that would preclude use of the alternative route for construction of the proposed facilities (Exh. HO-E-16). The Company stated that an LSP would determine procedures for the handling of contaminated soil encountered during construction, if any, including disposal at an approved off-site landfill or as backfill in the construction trench, as appropriate (id.).

The Company indicated that there are no known federally-protected or proposed endangered or threatened species in the vicinity of the alternative route (Exhs. HO-E-20, Att. 1; NEP-1, at 3-2).

The record demonstrates that impacts of the construction of the proposed facilities along the alternative route with respect to tree clearing, upland vegetation and potential soil erosion would be minimized. No contaminated soils would preclude construction of the proposed facilities, and no known rare or endangered species, or endangered species habitat would be adversely affected by the proposed construction. Thus, with respect to land resources, the primary and alternative routes are essentially comparable in all aspects with the exception of length: the alternative route is approximately 2.6 miles, or 0.7 miles shorter than the 3.3-mile primary route. Because impacts are minimal, however, the slightly greater length of the primary route would result in no additional impacts to land resources relative to the alternative route.

Accordingly, the Siting Board finds that the primary route would be comparable to the alternative route with respect to land resources.

(iii) Land Use

The Company submitted a description and map of land uses along the alternative route based on data from the MGIS office (Exh. NEP-1, at 3-57 to 3-59).

Land uses along the alternative route are the same as for the primary route from the Dewar Street substation to Victory Road (id. at 3-59). The alternative route then continues through a densely developed area marked by mixed residential and commercial land uses (id.). Thereafter the alternative route follows major commercial and commuter roadways to its southern end at the North Quincy substation (id.).

The Company anticipated more construction-related impacts along the alternative route south of Victory Road than along the segment of the primary route from Victory Road to the North Quincy substation due to the need to work in narrower, more congested commercial streets (id. at 3-66). The Company anticipated that work on the alternative route in Neponset Circle and at the Neponset River Bridge also would have temporary impacts on nearby businesses and residences (id.). The Company stated, however, that it would meet with businesspeople and residents along the alternative route to minimize disruption during construction as much as practicable (id.).

The Company indicated that 76 percent of the alternative route is within industrial and manufacturing zoning districts in the City of Boston (Exh. HO-RR-9). The remaining segment in Boston, approximately 1,000 feet, or seven percent of the total route, is in a district zoned for two-to-three family housing (id.). The portion of the alternative route in Quincy is located in a central business district (id.).

Zoning codes regulating the expansion of the Dewar Street and North Quincy substations would be the same for the proposed facilities along either the primary or alternative routes (Exh. NEP-1, at 3-58).

The Company submitted a letter from the MHC certifying that the MHC anticipated no impacts to significant historic or archaeological resources along the alternative route (Exh. HO-E-22, Att. 1).

Traffic impacts of the alternative route between Dewar Street substation and Victory Road would be the same as for the primary route (Exh. NEP-1, at 3-67, 3-68). The Company indicated that from Victory Road to Conley Street, traffic impacts would mainly consist of traffic disruptions resulting from the movement of equipment and material to and from the Company's work area (id. at 3-68 to 3-69). The Company anticipated that construction of the proposed facilities along the portion of the alternative route starting at Conley Street and ending at the North Quincy substation would involve limiting traffic to one lane in Conley, Tenean, and Norwood Streets for one to two weeks (id.). Installation of conduits in the approach to and along the Neponset River Bridge would also require lane closings: one southbound lane of the approach would be closed for one to two weeks and one southbound lane on the bridge itself would be closed occasionally as necessary over a three week period (id. at 3-69). In addition, the Company stated that due to construction, no on-street parking would be possible on Conley Street for one to two weeks or on Hancock Street, the street leading into the North Quincy substation, for four to five weeks (id.).

The Company indicated that, as along the primary route, access to fire and safety vehicles would be maintained and all applicable federal, professional and Company safety standards and policies would be followed (Exhs. HO-E-30; NEP-1, at 3-66).

The Company indicated that the source and nature of noise impacts along the alternative route would be the same as those along the primary route (Exh. NEP-1, at 3-65). The Company contended, however, that the greater number of residences and businesses in the vicinity of the alternative route would result in greater noise impacts (id.).

The Company stated that businesses and residents along the alternative route strongly urged the Company to construct its proposed facilities along the primary route because of existing and anticipated traffic impacts along the alternative route (id. at 3-69). The Company indicated that it held a total of over 100 meetings with diverse elements of the community in Boston and Quincy to discuss its proposed facilities (id.). The Company contended that there was a high degree of community acceptance of the proposed facilities along the primary route (id. at 3-69, App. A).

The record demonstrates that while zoning and safety impacts along the primary and alternative routes would be comparable, construction of the proposed facilities along the alternative route would occur in more densely commercial and residential areas than along the primary route, magnifying land use and noise impacts during the construction period. The record also demonstrates that construction along the narrower, more thickly settled streets along the alternative route would result in greater traffic congestion than is anticipated along the primary route. In addition, abutters have expressed serious concerns about land use impacts of the proposed facilities along the alternative route: the community and abutters have not expressed the same level of concern with respect to land use impacts of the proposed facilities along the primary route. Thus, the alternative route, though slightly shorter than the primary route, would likely generate significantly more land use impacts.

Accordingly, the Siting Board finds that the primary route would be preferable to the alternative route with respect to land use impacts.

(iv) Visual Impacts

The Company indicated that, as along the primary route, its proposed transmission lines along the alternative route would be installed underground (Exh. NEP-1, at 3-63). The Company stated that manholes for access to the proposed transmission lines would be flush mounted to ground level (id.). The Company also noted that the expansion of the Dewar Street and North Quincy substations would be the same whether the proposed facilities were constructed along the alternative or the primary route, with the same visual impacts (id. at 3-64).

The record demonstrates that there would be no permanent visual impacts associated with construction of the proposed transmission lines along the alternative route due to their installation underground. The record also demonstrates that the design and visual impacts of the expansions of the Dewar Street and North Quincy substations would be unaffected by the choice of transmission line route.

Accordingly, the Siting Board finds that the primary route and the alternative route would be comparable with respect to visual impacts.

(v) Magnetic Field Levels

The Company provided magnetic field levels for its proposed transmission lines and expanded facilities at Dewar Street and North Quincy substations (Exhs. HO-E-32; HO-E-33). The proposed transmission lines, when activated, would create the same level of magnetic fields along the primary and alternative routes (Exh. NEP-1, at 3-45). Magnetic field levels in the vicinity of the Dewar Street and North Quincy substations as a result of expansion of those facilities would also be the same, regardless of the choice of route (id. at 3-30, 3-33; Exhs. HO-E-32; HO-E-33; Company Brief at 20).

The record demonstrates that magnetic field levels in the vicinity of the proposed transmission lines and expanded Dewar Street and North Quincy substations would be the same along the primary and alternative routes, and far below levels found acceptable in previous Siting Board decisions (see Section III.2.a.v, above). While the alternative route is slightly shorter than the primary route, south of Victory Road it would pass through streets with more residential and commercial settlement than along the primary route. Consequently, the magnetic field impacts of the alternative route would be marginally greater than the magnetic field impacts of the primary route.

Accordingly, the Siting Board finds that the primary route would be slightly preferable to the alternative route with respect to magnetic field impacts.

(vi) Conclusions on Environmental Impacts

In Sections III.C.3.a(1) to (5), above, the Siting Board has found that the proposed facilities along the primary route would be preferable to the proposed facilities along the alternative route with respect to water resources and land use impacts, slightly preferable with respect to magnetic field impacts, and comparable with respect to land resources and visual impacts. Accordingly, the Siting Board finds the proposed facilities along the primary route would be preferable to the proposed facilities along the alternative route with respect to environmental impacts.

b. Cost of the Proposed Facilities along the Alternative Route and Comparison

The Company estimated that the installation of the proposed transmission lines along the alternative route would cost $12,300,000, or approximately $2,500,000 less than along the primary route (Exhs. HO-C-1; NEP-1, at 3-21).[51] The total costs (in 1997 dollars) of the proposed expansions of the Dewar Street and North Quincy substations -- $1,600,000 and $4,400,000, respectively -- would be the same for the primary and alternative routes (Exh. HO-RR-15) (see Section III.C.2.b, above). Thus, the estimated total cost of the proposed facilities along the alternative route, $20,900,000, would be approximately 89 percent of the $23,400,000 total cost estimated for the proposed facilities along the primary route (Exhs. HO-C-1; HO-RR-15).

The record demonstrates that the installation costs of the proposed facilities along the alternative route would be approximately 11 percent lower than corresponding costs for the proposed facilities along the alternative route. Accordingly, the Siting Board finds that the alternative route would be preferable to the primary route with respect to cost.

c. Conclusions

In comparing the proposed facilities along the primary and the alternative routes, the Siting Board has found that the primary route would be preferable with respect to environmental impacts, but that the alternative route would be preferable with respect to cost.

The additional costs of constructing the proposed project along the primary route are associated with the installation of the proposed transmission lines. Construction costs for the proposed expansion of the Dewar Street and North Quincy substations would be the same for the proposed facilities along either the primary or the alternative route.

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55 The Company indicated that the alternative route would result in savings of $2,300,000 in costs of construction and materials (Exhs. HO-C-1; NEP-1, at 3-21). Additional savings would stem from slightly lower engineering (-$100,000) and contingency (-$200,000) costs (Exh. HO-C-1). Right-of-way acquisition would be slightly higher (+$100,000) along the alternative route (id.).

While more costly, installing the proposed facilities along the primary route would substantially reduce a variety of land use impacts because it would avoid areas of denser business and residential development. The communities of both Boston and Quincy have also expressed their strong support for the primary route.

On balance, therefore, the Siting Board concludes that the additional expenditure of $2.3 million is warranted to avoid the significant impacts on residential neighborhoods and businesses associated with routing the proposed facilities through the built-up areas along the alternative route.

Accordingly, the Siting Board finds that the proposed facilities along the primary route would be preferable to the proposed facilities along the alternative route with respect to providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

IV. ZONING EXEMPTIONS/PUBLIC CONVENIENCE AND INTEREST

As noted in Section I.C, above, the Company filed two petitions with the Department, which are related to the proposed project under consideration by the Siting Board in the present proceeding and which have been consolidated for review in the Company's Siting Board proceeding. In one petition, the Company, pursuant to G.L. c. 164, § 72, sought a determination by the Department that NEPCo's proposed electric transmission lines are necessary and will serve the public convenience and be consistent with the public interest. In its other petition, the Company, pursuant to G.L. c. 40A, § 3, sought exemptions from the City of Quincy Zoning Ordinance with respect to the proposed modifications to the Company's existing North Quincy substation in the City of Quincy. Pursuant to G.L. c. 164, § 69H(2), the Siting Board applies the Department's standards of review for such petitions to the subject matter of the Company's petitions in a manner consistent with the above findings of the Siting Board.

A. Standard of Review

In its petition for a zoning exemption, the Company seeks approval under G.L. c. 40A, § 3, which, in pertinent part, provides:

> Land or structures used, or to be used by a public service corporation may be exempted in particular respects from the operation of a zoning ordinance or by-law if, upon petition of the corporation, the [D]epartment of [P]ublic [U]tilities shall, after notice given pursuant to section eleven and public hearing in the town or city, determine the exemptions required and find that the present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public....

Under this section, the Company first must qualify as a public service corporation (see Save the Bay, Inc. v. Department of Public Utilities, 366 Mass. 667 (1975)), and establish that it requires an exemption from the local zoning by-laws. The Company then must demonstrate that the present or proposed use of the land or structure is reasonably necessary for the public convenience or welfare.

In determining whether a company qualifies as a "public service corporation" for purposes of G.L. c. 40A, § 3, the Supreme Judicial Court has stated:

> among the pertinent considerations are whether the corporation is organized pursuant to an appropriate franchise from the State to provide for a necessity or convenience to the general public which could not be furnished through the ordinary channels of private business; whether the corporation is subject to the requisite degree of governmental control and regulation; and the nature of the public benefit to be derived from the service provided.

Save the Bay, 366 Mass. at 680.

In determining whether the present or proposed use is reasonably necessary for the public convenience or welfare, the Department must balance the interests of the general public against the local interest. Id. at 685-686; Town of Truro v. Department of Public Utilities, 365 Mass. 407 (1974). Specifically, the Department is empowered and required to undertake "a broad and balanced consideration of all aspects of the general public interest and welfare and not merely [make an] examination of the local and individual interests which might be affected." New York Central Railroad v. Department of Public Utilities, 347 Mass. 586, 592 (1964). When reviewing a petition for a zoning exemption under G.L. c. 40A, § 3, the

Department is empowered and required to consider the public effects of the requested exemption in the State as a whole and upon the territory served by the applicant. Save the Bay, supra, at 685; New York Central Railroad, supra, at 592.

With respect to the particular site chosen by a petitioner, G.L. c. 40A, § 3 does not require the petitioner to demonstrate that its preferred site is the best possible alternative, nor does the statute require the Department to consider and reject every possible alternative site presented. Martarano v. Department of Public Utilities, 401 Mass. 257, 265 (1987); New York Central Railroad, supra, at 591; Wenham v. Department of Public Utilities, 333 Mass. 15, 17 (1955). Rather, the availability of alternative sites, the efforts necessary to secure them, and the relative advantages and disadvantages of those sites are matters of fact bearing solely upon the main issue of whether the preferred site is reasonably necessary for the convenience or welfare of the public. Id.

Therefore, when making a determination as to whether a petitioner's present or proposed use is reasonably necessary for the public convenience or welfare, the Department examines: (1) the present or proposed use and any alternatives or alternative sites identified (see Massachusetts Electric Company, D.P.U. 93-29/30, at 10-14, 22-23 (1995) ("1995 MECo Decision"); New England Power Company, D.P.U. 92-278/279/280, at 19 (1994) ("1994 NEPCo Decision"); Tennessee Gas Pipeline Company, D.P.U. 85-207, at 18-20 (1986)) ("1986 Tennessee Decision"); (2) the need for, or public benefits of, the present or proposed use (see 1995 MECo Decision, supra, at 10-14; 1994 NEPCo Decision, supra, at 19-22; 1986 Tennessee Decision, supra, at 17); and (3) the environmental impacts or any other impacts of the present or proposed use (see 1995 MECo Decision, supra, at 14-21; 1994 NEPCo Decision, supra, at 20-23; 1986 Tennessee Decision, supra, at 20-25). The Department then balances the interests of the general public against the local interest, and determines whether the present or proposed use of the land or structures is reasonably necessary for the convenience or welfare of the public.[52]

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52 In addition, the Massachusetts Environmental Policy Act ("MEPA") provides that "[a]ny determination made by an agency of the commonwealth shall include a finding describing (continued...)

With respect to the Company's petition filed pursuant to G.L. c. 164, § 72, the statute requires, in relevant part, that an electric company seeking approval to construct a transmission line must file with the Department a petition for:

> authority to construct and use . . . a line for the transmission of electricity for distribution in some definite area or for supplying electricity to itself or to another electric company or to a municipal lighting plant for distribution and sale . . . and shall represent that such line will or does serve the public convenience and is consistent with the public interest. . . . The [D]epartment, after notice and a public hearing in one or more of the towns affected, may determine that said line is necessary for the purpose alleged, and will serve the public convenience and is consistent with the public interest.[53]

The Department, in making a determination under G.L. c. 164, § 72, is to consider all aspects of the public interest. Boston Edison Company v. Town of Sudbury, 356 Mass. 406, 419 (1969). Section 72, for example, permits the Department to prescribe reasonable conditions for the protection of the public safety. Id. at 419-420. All factors affecting any phase of the public interest and public convenience must be weighed fairly by the Department in a determination under G.L. c. 164, § 72. Town of Sudbury v. Department of Public Utilities, 343 Mass. 428, 430 (1962).

As the Department has noted in previous cases, the public interest analysis required by G.L. c. 164, § 72 is analogous to the Department's analysis of the "reasonably necessary for

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(...continued)
the environmental impact, if any, of the project and a finding that all feasible measures have been taken to avoid or minimize said impact." G.L. c. 30, § 61. Pursuant to 301 C.M.R. § 11.01(3), these findings are necessary when an Environmental Impact Report ("EIR") is submitted by the company to the Secretary of Environmental Affairs, and should be based on such EIR. Where an EIR is not required, c. 30, § 61 findings are not necessary. 301 C.M.R. § 11.01(3). In the present case, the Secretary of Environmental Affairs issued her determination that no EIR was required for the proposed project (See Certificate of the Secretary of Environmental Affairs on the Environmental Notification Form, EOEA No. 11477, dated February 11, 1998), and, therefore, a finding is not necessary in this case under G.L. c. 30, § 61.

53 Pursuant to the statute, the electric company must file with its petition a general description of the transmission line, provide a map or plan showing its general location, and estimate the cost of the facilities in reasonable detail. G.L. c. 164, § 72.

the convenience or welfare of the public" standard under G.L. c. 40A, § 3. See, New England Power Company, D.P.U. 89-163, at 6 (1993); New England Power Company, D.P.U. 91-117/118, at 4 (1991); Massachusetts Electric Company, D.P.U. 89-135/136/137, at 8 (1990). Accordingly, in evaluating petitions filed under G.L. c. 164, § 72, the Department relies on the standard of review for determining whether the proposed project is reasonably necessary for the convenience or welfare of the public under G.L. c. 40A, § 3. Id.

B. Analysis and Findings

NEPCo is an electric company as defined by G.L. c. 164, § 1, authorized to generate, distribute and sell electricity. New England Power Company, D.P.U. 92-255, at 2 (1994). Accordingly, NEPCo is authorized to petition the Department as a public service corporation for the determinations sought under G.L. c. 40A, § 3 in this proceeding.

G.L. c. 40A, § 3, authorizes the Department to grant to public service corporations exemptions from local zoning ordinances or by-laws if the Department determines that the exemption is required and finds that the present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public. With respect to the Company's petition filed pursuant to G.L. c. 40A, § 3, the Company seeks exemption from the operation of the special permit requirement of the Quincy Zoning Ordinance.[54] Based on its review of the City of Quincy Zoning Ordinance, the Siting Board concludes that the special permit requirement could impede the construction, operation and maintenance of the Company's proposed project. Therefore, the Siting Board finds that the Company requires exemptions from the above section of the City of Quincy Zoning Ordinance for the construction, operation and maintenance of the proposed project.

Pursuant to G.L. c. 40A, § 3, the Siting Board next examines whether the Company's proposed use of land and structures as set forth in its petitions is reasonably necessary for the convenience or welfare of the public. In making its findings, the Siting Board relies on the

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54 The Company has identified this section as the provision "shown on page 32 of the Quincy Zoning Ordinance" (Exh. HO-E-12(S)).

analyses in Sections II and III, above. In those sections, the Siting Board found that the Company's reliability criteria are reasonable for purposes of this review, and that there is a need for additional energy resources based on the Company's reliability criteria with respect to common mode outages (see Sections II.A.3.a. and b, above). The Siting Board also found that the supply to Quincy's two substations -- Field Street and North Quincy -- does not meet the Company's reliability criteria with respect to common mode outages. Specifically the Siting Board stated that the need for the proposed facilities is based, not on the precise load projected for a specific future year, but on the unacceptable consequences of a three-day power loss to some or all of Quincy in the event of a common mode failure.

In addition, the Siting Board found that the Company has demonstrated that acceleration of C&LM programs could not eliminate the identified need in Quincy for additional energy resources (see Section II.A.3.d, above). The Siting Board also noted that the addition of energy resources to supply Quincy could alleviate potential overloading elsewhere on the southeastern Massachusetts transmission system within the next ten years by providing an independent 115 kV supply source for Quincy, thereby relieving contingency load on equipment at Holbrook substation. Consequently, the Siting Board found that additional energy resources currently are needed for reliability purposes in Quincy.

The Siting Board notes above that the Company evaluated a reasonable range of alternatives to the proposed project, including six alternative approaches for meeting the identified need in Quincy. The record further indicates that the Company considered possible environmental impacts of the proposed project that may be of concern to the surrounding community, including water resources, land resources, land use, visual impacts, and magnetic field level impacts. The record also indicates that the Company would implement measures to mitigate these impacts.

Thus, with the implementation of the mitigation measures identified by the Company, the Siting Board finds that the general public interest in the construction, operation and maintenance of the proposed transmission lines and modifications to the existing North Quincy substation outweighs the minimal impacts of the Company' proposed project on the local community. Accordingly, the Siting Board finds that the proposed transmission lines and proposed modifications to the existing North Quincy substation are reasonably necessary for the convenience or welfare of the public and exempts NEPCo from the operation of the special permit requirement (as identified by the Company) of the City of Quincy Zoning Ordinance.

With regard to the Company's petition filed pursuant to G.L. c. 164, § 72, the Siting Board notes that the Company has complied with the requirements that it describe the proposed transmission lines, provide a map or plan showing the general location of the transmission lines, and estimate the cost of the transmission lines in reasonable detail. Consistent with Department precedent and the public interest analysis above, the Siting Board here finds that NEPCo's proposed transmission lines are necessary for the purpose alleged, and will serve the public convenience and are consistent with the public interest.

V. DECISION

The Siting Board has found that additional energy resources are needed for reliability purposes in the City of Quincy. The Siting Board also has found that the Company's identification of a need for additional energy resources in Quincy is consistent with its most recently approved long range forecast. Consequently, the Siting Board finds that the proposed project is consistent with the most recently approved long-range forecast of NEPCo.

The Siting Board has found that both the proposed project and a low voltage reinforcement alternative would meet the identified need. The Siting Board also has found that the proposed project is preferable to the low voltage alternative.

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

The Siting Board further has found that, with the implementation of proposed mitigation and planned compliance with all applicable local, state, and federal requirements, the environmental impacts of the proposed facilities along the primary route would be minimized.

The Siting Board further has found that the proposed facilities along the primary route would achieve an appropriate balance among conflicting environmental concerns as well as between environmental impacts and cost.

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

Accordingly, the Siting Board APPROVES the Company's petition to construct two 3.3-mile, 115-kilovolt underground electric transmission lines and to expand its Dewar Street and North Quincy substations in the Cities of Boston and Quincy, Massachusetts using the Company's primary route.

In addition, the Siting Board has found that NEPCo's proposed transmission lines are necessary for the purpose alleged, and will serve the public convenience and are consistent with the public interest; and

The Siting Board GRANTS the Company's petition for an exemption from the operation of the special permit requirement of the City of Quincy Zoning Ordinance for the purposes of expanding its substation in North Quincy in conjunction with constructing and operating its two proposed transmission lines.

The Siting Board notes that the findings in this decision are based on the record in this case. A project proponent has an absolute obligation to construct and operate its facility in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Company to notify the Siting Board of any changes other than minor variations to the proposal so that the Siting Board may decide whether to inquire further into a particular issue. The Company is obligated to provide the Siting Board with sufficient information on changes to the proposed project to enable the Siting Board to make these determinations.

Jolette A. Westbrook
Hearing Officer

Dated this 9th day of October, 1998.

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of October 8, 1998 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Janet Gail Besser (Chair, EFSB/DTE); James Connelly (Commissioner, DTE); W. Robert Keating (Commissioner, DTE); and David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development).

Janet Gail Besser

Janet Gail Besser
Chair

Dated this 9th day of October, 1998.

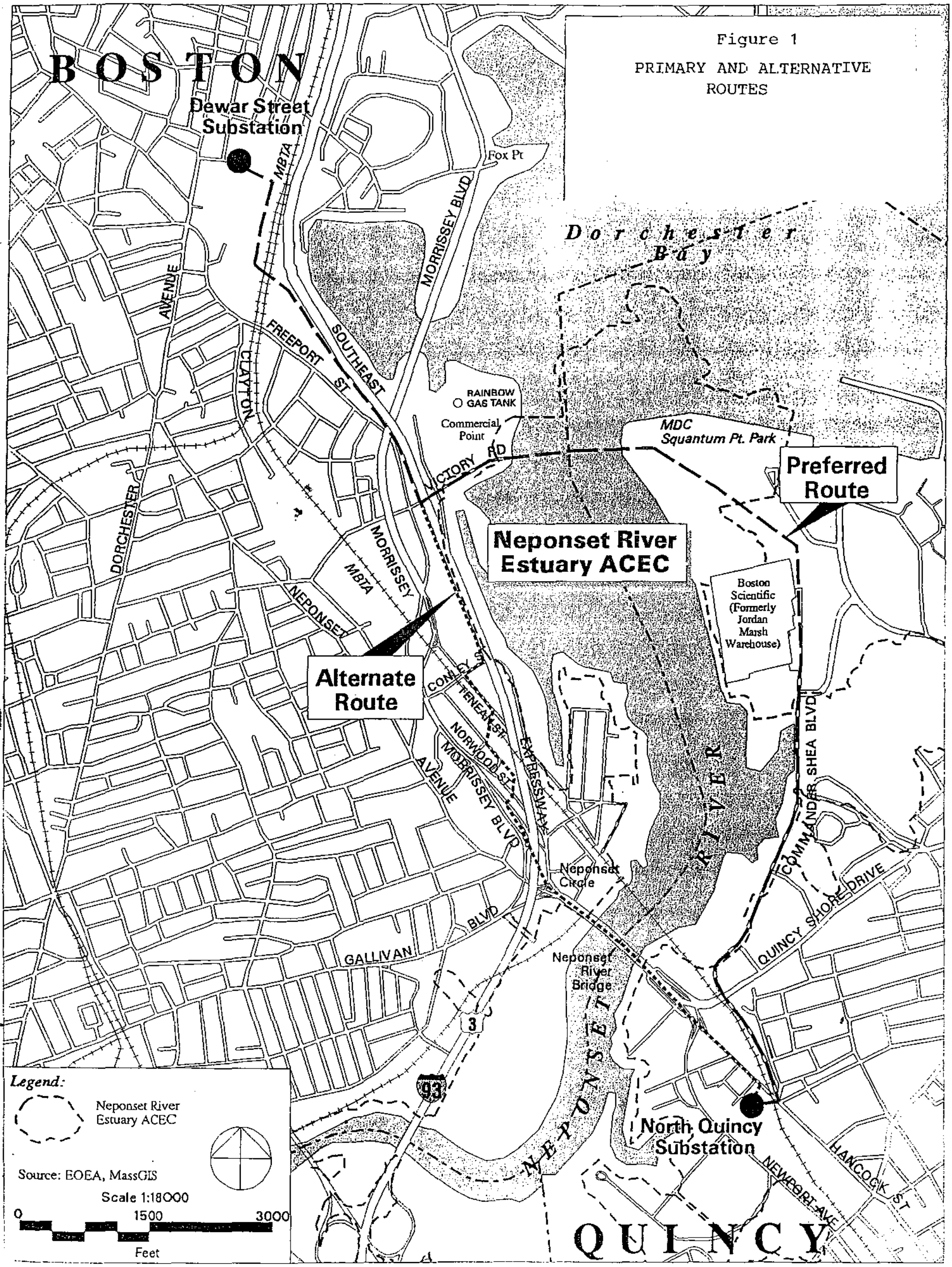

Figure 1

PRIMARY AND ALTERNATIVE ROUTES

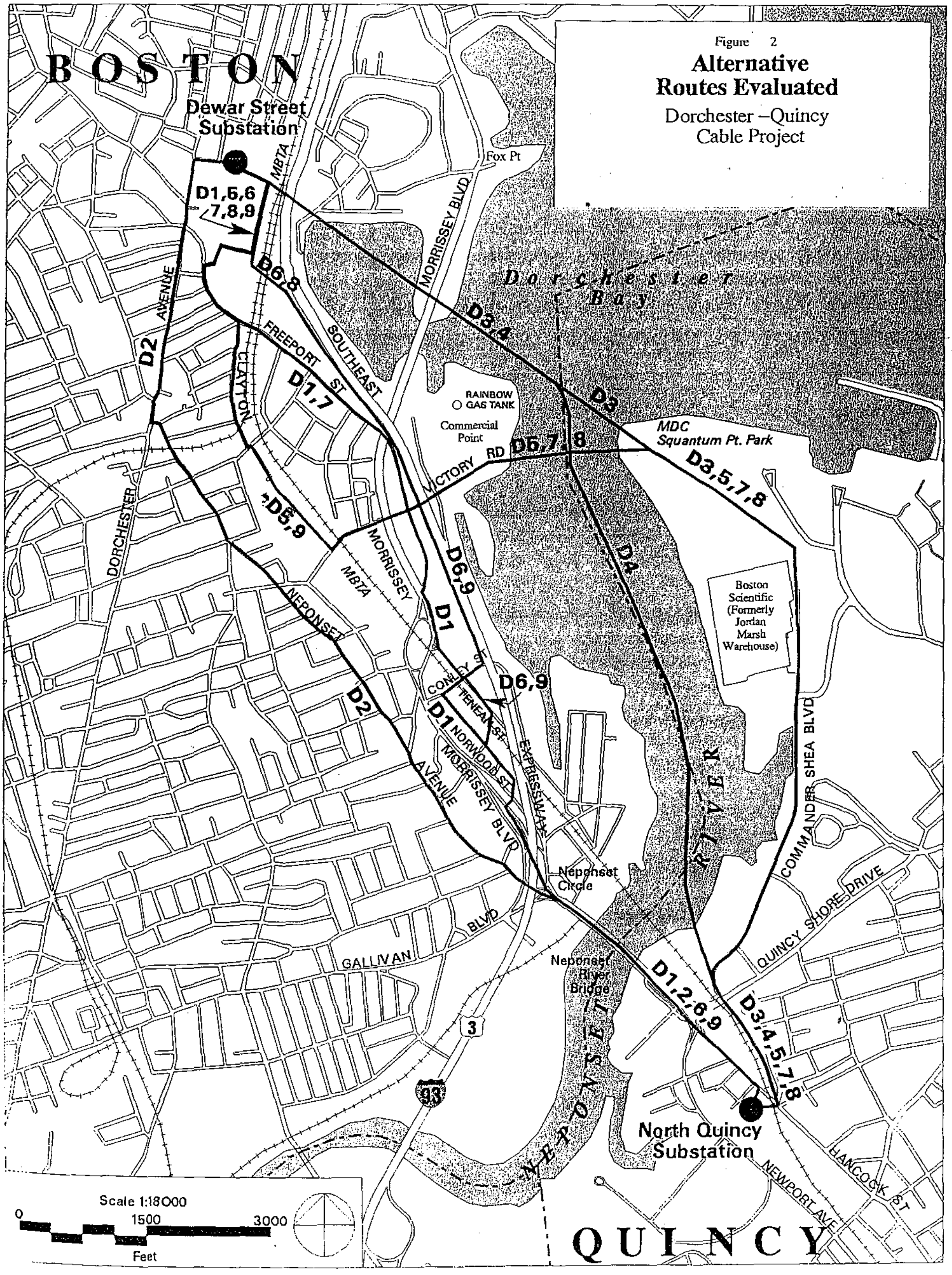

Figure 2
Alternative Routes Evaluated
Dorchester –Quincy Cable Project
BOSTON
Dewar Street Substation
D1,5,6 7,8,9
MBTA
Fox Pt
MORRISSEY BLVD
Dorchester Bay
D6,8
D3,4
D2
AVENUE
FREEPORT ST
CLAYTON
D1,7
SOUTHEAST
RAINBOW GAS TANK
Commercial Point
D3
MDC Squantum Pt. Park
VICTORY RD
D5,7,8
D3,5,7,8
D5,9
DORCHESTER
MORRISSEY
MBTA
D6,9
D4
Boston Scientific (Formerly Jordan Marsh Warehouse)
NEPONSET
D1
CONLEY ST
D6,9
D2
TENEAN ST
D1
NORWOOD ST
MORRISSEY BLVD
EXPRESSWAY
AVENUE
RIVER
COMMANDER SHEA BLVD
Neponset Circle
QUINCY SHORE DRIVE
BLVD
GALLIVAN
Neponset River Bridge
D1,2,6,9
D3,4,5,7,8
3
93
NEPONSET
North Quincy Substation
HANCOCK ST
NEWPORT AVE
Scale 1:18000
0
1500
3000
Feet
QUINCY

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

Such petition for appeal shall be filed with the Siting Board within twenty days after the date of service of the decision, order or ruling of the Siting Board, or within such further time as the Siting Board may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the clerk of said court. (Massachusetts General Laws, Chapter 25, Sec. 5; Chapter 164, Sec. 69P).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of Berkshire Power Development, Inc. for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 95-1

FINAL DECISION

ON COMPLIANCE

Robert P. Rasmussen
Hearing Officer
December 22, 1997

On the Decision:

Phyllis Brawarsky
William Febiger

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<u>Interested Person</u>

TABLE OF CONTENTS

The Energy Facilities Siting Board hereby APPROVES the petition of Berkshire Power Development Inc. to construct a 252 megawatt bulk generating facility and ancillary facilities in Agawam, Massachusetts.

I. INTRODUCTION

On June 19, 1996, the Energy Facilities Siting Board ("Siting Board") conditionally approved the petition of Berkshire Power Development, Inc. ("BPD") to construct a 252 megawatt ("MW") natural gas-fired, combined-cycle independent power plant on an approximately 40-acre undeveloped parcel of land located at the Shoemaker Industrial Park in the Town of Agawam, Massachusetts ("Town" or "Agawam") which would commence commercial operation in 1999. Berkshire Power Development, Inc., 4 DOMSB 221, 237 (1996) ("BPD Decision"). In the BPD Decision, the Siting Board found that BPD had established that, upon confirmation by the Siting Board of adequate compliance with specific conditions, the proposed project is likely to be viable. Id. at 346, 447-448. Therefore, the Siting Board specified additional evidence on project viability that BPD would need to provide for the Siting Board to make the additional findings that would support a decision to allow BPD to construct its proposed facility. Id.

As a result, the Siting Board approved BPD's petition subject to four conditions regarding viability.[1] Id. On November 25, 1997, BPD submitted a compliance filing relative to the viability conditions and certain other issues.[2]

The viability conditions required BPD to provide: (1) an executed engineering, procurement and construction contract ("EPC contract") between BPD and Black and Veatch Construction, Inc. and ABB Power Generation ("B&V/ABB Power Generation"), the entity which will construct the project; 2) an executed interconnection agreement between BPD and

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1 The Board also imposed six additional conditions relative to the construction and operation of the facility. 4 DOMSB at 448-449.

2 The viability compliance filing is hereby moved into evidence as Exhibit HO-V-32 with Attachments 1 through 9b. BPD has requested confidential treatment of Attachments 1 through 5 and such treatment is hereby granted.

Northeast Utilities ("NU"); 3) an executed operations and maintenance ("O&M") agreement between BPD and ABB Operations and Maintenance Department ("ABB O&M"), the entity which will operate and maintain the proposed facility; and 4) an executed contract for firm transportation of natural gas for 335 days or more to the proposed facility from Wright, New York or a comparable location. Id. at 447-448.

The Siting Board also found that upon compliance with all conditions set forth in the decision, the construction of the proposed facility will be consistent with providing a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost. Id. at 446.

In addition to the conditions imposed, the Siting Board required BPD to notify the Siting Board of any changes to BPD's proposed project, other than minor variations, so that the Siting Board could decide whether to further inquire into any issue associated with a particular change. Id. at 450. Accordingly, in its viability compliance filing, BPD also noted three changes in the project: a change in the joint development team for the project; improvements to the project resulting from design changes in the ABB GT-24 turbine; and changes in back-up fuel storage capacity and deliveries to the facility resulting from BPD's settlement with the Agawam Zoning Board of Appeals ("ZBA"). The Siting Board addresses the viability compliance and the three changes in the project in the following sections.

II. PROJECT VIABILITY

A. Standard of Review

The Siting Board determines that a proposed non-utility generating project is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the life of its power sales agreements. U.S. Generating Company, EFSB 96-4, 1, 71-72 (1997) ("USGen Decision"); BPD Decision, 4 DOMSB at 328-329; Northeast Energy Associates, 16 DOMSC 335, 378-380 (1987) ("NEA Decision").

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable,[3] and (2) that the project is likely to be constructed within the applicable time frames and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements. USGen Decision, EFSB 96-4, at 71-72; BPD Decision, 4 DOMSB at 328-329; NEA Decision, 16 DOMSC at 378-380.

B. Construction

With respect to BPD's construction strategy, the Siting Board considered whether the project is reasonably likely to be constructed and go into service as planned. BPD Decision, 4 DOMSB at 332. The Siting Board reviewed a Term Sheet, which was to be the basis for negotiation of the final EPC contract. Id. at 333-35. The Siting Board found that BPD would be able to demonstrate that the project was reasonably likely to be constructed and go into service as planned by submitting a signed EPC contract between BPD and B&V/ABB

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3 In the BPD Decision, the Siting Board found that BPD had established that the proposed project is financiable. 4 DOMSB at 332.

Power Generation that "contains all of the significant provisions included in the Term Sheet." Id. at 336. The Siting Board found that the Term Sheet submitted by BPD (Exh. HO-V-13) included "a number of advantageous provisions, such as incentive and penalty terms, which the Siting Board has recognized in previous reviews as ensuring timely and quality construction projects." Id.

In response to this condition, BPD presented to the Siting Board an executed EPC contract between BPD and B&V/ABB Power Generation. The executed EPC contract contains the "advantageous provisions" that were included in the Term Sheet (Exh. HO-V-32(att. 1)). Section 6.1 of the EPC contract provides for a lump sum price (id. at 31). Section 4.1 provides for a guaranteed schedule (id. at 28). Section 29.1.1 provides for liquidated damages for failure to achieve substantial completion by the guaranteed completion date (id. at 62). Section 29.1.2 provides for liquidated damages for failure to achieve operational guarantees (id. at 63). Section 30.1 provides for an early completion bonus (id. at 72). Section 15 provides for warranties (id. at 42). Section 27.2 provides for insurance (id. at 57). Sections 22 through 26 provide for acceptance testing (id. at 52).

BPD noted that some details in the EPC contract vary from the submitted Term Sheet (Exh. HO-V-32, at 2-3). BPD explained that most of these variances are relatively minor and are the expected result of the usual process of developing a term sheet into a more comprehensive and formal contract (id. at 2). BPD further noted that some variances reflect the improvements in turbine design efficiency that BPD presented to the staff of the Siting Board on May 7, 1997 and which the Siting Board staff concluded would not alter in any substantive way either the assumptions or the conclusions reached in the Siting Board's analysis of environmental impacts in the BPD Decision (see Exh. HO-V-32(atts. 8 & 9)). BPD contends that these improvements in output, heat rate, and overall economic efficiency have only served to improve the EPC contract in comparison to the Term Sheet (id. at 2-3). The remaining variances reflect efforts by BPD to negotiate even more beneficial performance standards.

Based on its review of the EPC Contract, the Siting Board finds that the protections reflected in the guarantees, warranties, milestones, and other provisions of the EPC contract, ensure that BPD's proposed project is likely to be constructed on schedule and to perform as expected.

C. Interconnection to the Regional Electric Transmission Grid

The Siting Board found that to establish that the proposed project is likely to be capable of being dispatched as expected, BPD must submit a signed interconnection agreement between BPD and Northeast Utilities ("NU"). BPD Decision, 4 DOMSB at 336. BPD submitted a signed system impact study agreement with NU for the interconnection planned for the proposed BPD facility (Exh. HO-V-32(att. 2)).[4] Following the close of the evidentiary record in the underlying proceeding, the Federal Energy Regulatory Commission ("FERC") issued an order that requires utilities owning, controlling, or operating transmission facilities to allow others open and equal access to the regional transmission grid. FERC Order 888 (April 24, 1996). FERC Order 888 requires utilities that own, control or operate transmission facilities used in interstate commerce to file tariffs setting rates and other terms for service to all customers for network, load-based service and point-to-point, contract-based service. BPD stated in its compliance filing that pursuant to its right to access the electric transmission grid under FERC Order 888, it will request service under the filed tariff rather than through a separate agreement (Exh. HO-V-32, at 3). BPD requested that the Siting Board accept its rights under FERC Order 888 as proof of the proposed project's access to the regional transmission grid.

Based on NU's open access tariffs, filed pursuant to FERC Order 888, and the signed system impact study agreement, the Siting Board finds that BPD has access to the regional transmission grid.

Consistent with the Siting Board's conditional approval in the BPD Decision, 4 DOMSB at 336, the Siting Board here finds that BPD has complied with (1) the condition

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4 The Siting Board notes that paragraph 8 of the system impact agreement provides that BPD's rights to wheel over or interconnect with NU's transmission or distribution system "shall be provided for under separated agreement and in accordance with the [NU]'s open access tariff" (Exh. HO-V-32(att. 2) at ¶ 8).

relative to the provision of a signed EPC contract, and (2) given the post-BPD Decision changed federal requirements as a result of FERC Order 888, the intent of the condition relative to the provision of a signed interconnection agreement. Accordingly, the Siting Board finds that BPD has established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives. Further, in conjunction with the finding as to the financibility of BPD's proposed project (see BPD Decision, 4 DOMSB at 332), the Siting Board finds that BPD has established that its proposed project meets the Siting Board's first test of viability.

D. Operations

With respect to operation of the proposed project, the Siting Board examined whether the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. BPD Decision, 4 DOMSB at 328. Consistent with this objective, the Siting Board evaluated the ability of the project proponent or other reasonable entities to operate and maintain the facility in a manner which ensures a reliable energy supply. Id. at 337. In the underlying case, the Siting Board required BPD to establish that experienced and competent entities are contracted for, or otherwise committed to, the performance of critical tasks. Id. The Siting Board required that such tasks be enumerated in detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements. Id.

The Siting Board found that in order to establish that BPD's proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, BPD must provide a copy of a signed O&M agreement with the project's selected O&M contract provider. Id. at 338, 448. The Siting Board stated that to satisfy this condition, the executed O&M agreement should be similar in all significant provisions to the draft contract submitted by BPD during the course of the proceeding. Id. at 338-39.

In response to this condition, BPD presented to the Siting Board an executed term sheet with ABB (Exh. HO-V-32(att. 3)). The executed term sheet contains bonus, penalty and incentive provisions related to availability, heat rate, capacity and budget variation similar or superior to those in the draft contract, which ensure that the project with the turbine design enhancements previously reviewed by the Siting Board will operate in a reliable manner over the term of the agreement (id.).

The Siting Board finds that the executed term sheet is similar or superior in all significant provisions to the draft submitted during the proceeding. Accordingly, the Siting Board finds that BPD has demonstrated that its proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

E. Fuel Acquisition

In considering BPD's fuel acquisition strategy, the Siting Board considered whether BPD's strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. BPD Decision, 4 DOMSB at 343. The Siting Board found that a firm transportation contract from a major interconnection point to the proposed project is essential to ensuring that BPD's gas supply strategy is viable. Id. at 344. The Siting Board therefore required BPD to provide the Siting Board with a signed contract(s) for 335 days or more of firm transportation from Wright, New York or a comparable location, or a comparable agreement, in order to secure final approval of the proposed project. Id. at 344-345.

In response to this condition, BPD presented to the Siting Board a fuel management services agreement with El Paso Energy Marketing (Exh. HO-V-32(att. 4)).[5] El Paso Energy Marketing's obligations will be guaranteed by El Paso Natural Gas Company, which recently acquired Tennessee Gas Pipeline Company (id. (att. 4) at 1). Pursuant to the fuel management services agreement, El Paso Energy Marketing will provide all the natural gas and fuel oil requirements of the facility (id. (att. 4) at 1, 2-3, 5-6). The fuel management services agreement calls for initial arrangements through an assignment of firm capacity from

5 In addition, BPD provided a copy of an executed firm natural gas transportation assignment agreement between Power Development Company ("PDC") and Bay State Gas Company (Exh. HO-V-32(att. 5)). PDC is one of the development partners of the proposed BPD project (see BPD Decision, 4 DOMSB at 238),

Bay State Gas Company on the Tennessee Gas Pipeline system from Zone 0 or Zone 1 (Gulf Coast) to BPD's proposed project (Exh. HO-V-32(att. 4) at 2-3).

The Siting Board finds that BPD has demonstrated that its gas supply strategy is viable. Accordingly, the Siting Board finds that BPD's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project.

Consistent with the Siting Board's conditional finding in the BPD Decision, 4 DOMSB at 345, the Siting Board here finds that BPD has complied with (1) the condition relative to the provision of a signed O&M contract and, (2) the condition relative to the provision of a signed contract(s) for 335 days or more of firm transportation from Wright, New York or a comparable location. Accordingly, the Siting Board finds that BPD has established that its proposed project meets the Siting Board's second test of viability.

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

F. Additional Issues

The Siting Board requires that project proponents notify the Siting Board of any changes other than minor variations to the proposal as presented to the Siting Board, so that it may decide whether to inquire further into such issues. BPD Decision, 4 DOMSB at 450. In addition to the viability compliance issues addressed above, BPD also provided the Siting Board with information concerning three changes in the project: (1) a change in the joint development team for the project; (2) improvements to the project resulting from design changes in the ABB GT-24 turbine; and (3) changes in back-up fuel storage capacity and deliveries to the facility resulting from BPD's settlement with the ZBA.

1. Change in Development Team

With respect to the change in the development team, BPD stated in its compliance filing that El Paso Energy Corporation[6] signed a joint development agreement with PDC to jointly develop, construct and operate the proposed project (Exh. HO-V-32 at 5). BPD stated that with the addition of El Paso Energy Corporation, former development members ABB Energy Ventures and Cogeneration Services Corporation ("CSC") had withdrawn from the development team.[7] BPD stated that El Paso Energy Corporation is one of the world's largest energy corporations (id. at 6). BPD noted that El Paso Energy Corporation is a publicly traded company with a holding company structure of five business units, including a natural gas transmission subsidiary with the nation's only integrated coast-to-coast natural gas pipeline; a field services company that provides gathering, treating, processing, compression and intrastate transmission services to gas producers; an energy marketing company skilled in the gas, oil, electricity and natural gas liquids markets; and an international energy project development group (id. at 6 and (att. 6)). BPD further stated that El Paso Energy Corporation has extensive experience in gas-fired power generation (id. at 7). BPD noted that, currently, El Paso Energy Corporation is a co-owner, developer and operator of cogeneration, baseload and peaking projects around the world, including the MASSPOWER plant in Springfield, Massachusetts (id. at 6 and (att. 6)). BPD stated that in 1997, El Paso Energy Corporation had over 1,000 MW in operation, including three plants in the United States, one in Hungary and two in Argentina with an additional 1,450 MW under construction in four countries, including integrated pipeline and power projects in South Sulawesi, Indonesia and Aguaytia, Peru (id.).

BPD noted that, in addition to providing fuel management capability as described in Section II.E, above, El Paso Energy Marketing will provide power marketing services to the BPD project (Exh. HO-V-32 at 6).

The Siting Board finds that BPD has demonstrated that El Paso Energy Corporation is

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6 El Paso Energy Corporation is the parent of Tennessee Gas Pipeline Company, the interstate pipeline to which the BPD's proposed project will be interconnected.

7 El Paso Energy Corporation is the successor to both ABB Energy Ventures and Cogeneration Services Corporation (Exh. HO-V-32, at n.7).

a viable substitute development partner. Like ABB Energy Ventures and CSC, El Paso Energy Corporation has a broad range of experience in overall project development. See BPD Decision, 4 DOMSB at 331. In addition, like ABB Energy Ventures, El Paso Energy Corporation has substantial worldwide experience in the power development field, as well as significant capital resources. See Id. at 331-332. Accordingly, the Siting Board finds that the substitution of El Paso Energy Corporation for ABB Energy Ventures and CSC as a development partner does not require further inquiry.

2. ABB GT-24 Turbine Design Changes

BPD noted that design changes in the ABB GT-24 turbine have resulted in improvements to the project (Exh. HO-V-32 at 6). As originally proposed, the project had a planned capacity of 252 MW (net nominal). BPD Decision, 4 DOMSB at 237, 447. BPD informed the Siting Board by letter of May 7, 1997 that, as a result of the actual performance of the GT-24 turbine design, the average annual output of the facility would increase by 18 MW (about 7%) and the net plant heat rate would improve by approximately 150 Btu/kWh (Exh. HO-V-32(att. 7)).

The Siting Board staff stated by letter of May 21, 1997 that the design changes in the ABB GT-24 turbine would improve the project's output, heat rate, and overall economic efficiency, without altering in any substantive way either the assumptions or the conclusions reached in the Siting Board's analysis of the project's environmental impacts in the underlying proceeding (Exh. HO-V-32(att. 8)). The staff determined that further inquiry into the design changes was not required (id.).

The Siting Board agrees with the staff's determination and finds that the ABB GT-24 turbine design change does not warrant further inquiry.

3. Changes due to ZBA Settlement Agreement

Following the issuance of the Siting Board's decision, BPD negotiated and executed a Settlement Agreement with the ZBA (Exh. HO-V-32(att. 9a)). Two conditions imposed by the Settlement Agreement will result in a change in on-site oil storage capacity and provide for more flexible fuel oil delivery hours than those referenced in the BPD Decision (Exhs. HO-V-32, at 7; HO-V-32(att. 9a, Conditions 4 & 25).

With respect to the first of these conditions, as originally proposed, the fuel acquisition strategy for the project provided for a back-up fuel supply plan which included a three-day, on-site oil supply. BPD Decision, 4 DOMSB at 343-344. Under the terms of the Settlement Agreement, BPD committed to use good-faith efforts to eliminate all on-site fuel storage, and failing such elimination, agreed to limit the fuel storage tanks to forty feet in height and to a capacity of one-half of that originally contemplated (Exh. HO-V-32(att. 9b, Condition 4)). With respect to the second of these conditions, BPD acknowledged that the Siting Board noted in the BPD Decision that BPD had committed to limiting delivery of fuel oil to between the hours of 9:30 a.m. to 2:00 p.m. to avoid conflicts with the Agawam school bus schedule. 4 DOMSB at 409. As a condition of the Settlement Agreement however, deliveries may take place between the hours of 7:00 a.m. and 6:00 p.m., with special care taken between the hours of 7:00 a.m. to 9:00 a.m. and 2:00 p.m. to 4:00 p.m., in light of school-pickup and drop-off times (Exh. HO-V-32(att. 9b, Condition 25)).

BPD requested that the Siting Board defer to the specific conditions imposed by local authorities concerning oil storage and deliveries to the facilities (Exh. HO-V-32 at 7). In so requesting, BPD noted that the Department of Public Utilities ("Department") recently approved BPD's petition for an exemption from the zoning by-laws of the Town of Agawam. Berkshire Power Development, Inc., D.P.U. 96-104 (1997). In that approval, the Department relied on the findings of the Siting Board and local permitting authorities, including those found in the Settlement Agreement, and noted that in its balancing of general public and local interests that the local interests would be protected by BPD's compliance with all conditions contained in those documents. Id. at 44-45.

The Siting Board finds that BPD has demonstrated that changes to its proposed project resulting from BPD's compliance with the Settlement Agreement will not alter in any substantive way either the assumptions or conclusions reached in the Siting Board's analysis of the proposed project's environmental impacts. First, the reduction in the amount of fuel to be stored on the site should not materially affect the viability of BPD's proposed project or prevent it from providing a necessary energy supply for the Commonwealth. And second, the Siting Board finds that safety issues will not be materially affected by deferring to the ZBA with regard to the fuel delivery schedule. Accordingly, the Siting Board finds that the changes in on-site fuel storage capacity and deliveries do not require further inquiry. The Siting Board notes that this finding is consistent with the Department's reliance on BPD's compliance with the conditions in the Settlement Agreement in its decision in D.P.U. 96-104 granting BPD's request for a zoning exemption.[8]

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8 In making this finding, the Siting Board notes that the conditional approval which was granted BPD in 1996 requires commencement of construction of BPD's proposed project by June 19, 1999. BPD Decision, 4 DOMSB at 449, 450. The Siting Board further notes that the Settlement Agreement becomes null and void if construction does not commence by January 5, 1998 (Exh. HO-V-32(att. 9b, Condition 47). Nothing in this Decision shall be read to imply that the Siting Board approval is either contingent upon (1) construction of BPD's proposed project commencing at the earlier date set forth in the Settlement Agreement, or (2) the continued validity of the Settlement Agreement.

III. DECISION

In the BPD Decision, the Siting Board found that upon compliance with the four viability conditions set forth therein, the construction of the proposed generating facility is consistent with providing a necessary energy supply to the Commonwealth at the lowest possible cost. 4 DOMSB at 447-48.

Here, the Siting Board has found that BPD has complied with the four viability conditions set forth in Section II.C. of the BPD Decision. Id.

In addition, consistent with the Siting Board's directive to BPD to inform the Siting Board of any changes to BPD's proposed project, other than minor variations, BPD has informed the Siting Board of three such changes. The Siting Board has found that none of these changes require further inquiry.

Robert P. Rasmussen
Hearing Officer

Dated this 22nd day of December, 1997

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of December 19, 1997 by the members and designees present and voting. Voting for approval of the Tentative Decision as amended: Sonia Hamel, Acting Chair (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); John D. Patrone (Commissioner, DTE); James Connelly (Commissioner, DTE); David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development); Joseph Faherty (Public Member); and Nancy Brockway (Public Member).

Sonia W. Hamel

Sonia Hamel
Acting Chair

Dated this 22nd day of December, 1997

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of U.S. Generating Company for Approval to Construct a Bulk Generating Facility and Ancillary Facilities	)	EFSB 96-4

FINAL DECISION
ON COMPLIANCE

Jolette A. Westbrook
Hearing Officer
May 20, 1998

On the Decision:
William Febiger

APPEARANCES: Mary Beth Gentleman, Esquire
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The Energy Facilities Siting Board hereby APPROVES the Petition of U.S. Generating Company to construct a nominal net 360-megawatt natural gas-fired power generation and ancillary facilities in Charlton, Massachusetts.

I. INTRODUCTION

On November 3, 1997, the Energy Facilities Siting Board ("Siting Board") conditionally approved the petition of U.S. Generating Company ("USGen") to construct a nominal net 360-megawatt ("MW") natural gas-fired, combined-cycle electric power plant on approximately 15 acres of a 120-acre site located in the Town of Charlton, Massachusetts ("Town" or "Charlton"). U.S. Generating Company Decision, EFSB 96-4, 1 (1997) ("USGen Decision"). The proposed facility is scheduled to begin commercial operation in the year 2000. Id. In the USGen Decision, the Siting Board found that USGen had established that, upon compliance with three conditions, the proposed project is likely to be viable. Id. at 83-84, 86, 93. In addition, the Siting Board found that, with the implementation of certain conditions pertaining to CO_2 mitigation, water resources, wetlands impacts, visual impacts, noise, traffic, and fogging and icing, the environmental impacts of the proposed facility at the primary site would be minimized, consistent with minimizing cost. Id. at 186-187.

On March 25, 1998, USGen submitted a compliance filing relative to these conditions and certain changes to the project as approved in the USGen Decision ("Compliance Filing"). On April 15, 1998, USGen provided supplemental information to its March 25, 1998 compliance filing ("Compliance Supplement"). Finally, on May 4, 1998, USGen provided a copy of its Order of Conditions from the Southbridge Conservation Commission ("Order of Conditions").[1] The Siting Board addresses the Company's compliance with the viability and

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1 The Compliance Filing, including all attachments, is hereby moved into evidence as Exhibit EFSB-CF, with exhibits A through L. The Compliance Supplement, including all attachments and maps, is hereby moved into evidence as Exhibit EFSB-CF(S), with exhibits 1 through 6. The Order of Conditions, including all attachments, is hereby moved into evidence as Exhibit EFSB-CF(S2).

environmental conditions and the changes in the project in the following sections.

II. PROJECT VIABILITY

A. Standard of Review

The Siting Board determines that a proposed NUG is likely to be a viable source of energy if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least-cost source of energy over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 346.

In order to meet the first test of viability, the proponent must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within the applicable time frame and will be capable of meeting performance objectives. In order to meet the second test of viability, the proponent must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. Dighton Power Decision, EFSB 96-3, at 24; Berkshire Power Decision, 4 DOMSB at 345.[2]

B. Construction

With respect to USGen's construction strategy, the Siting Board considered whether the project is reasonable likely to be constructed and go into service as planned. USGen Decision, EFSB 96-4, at 75. In the underlying case, the Siting Board reviewed a sample engineering, procurement and construction contract ("EPC contract") that specified terms that the Company generally expected to include in any final EPC contract. Id. at 79.

[2] In the USGen Decision, EFSB 96-4, at 74-75, we stated that we would open a Notice of Inquiry regarding viability to determine whether we would affirm our current standard of review or articulate a new one. We stated that in the interim, we would continue to apply our existing standard of review while remaining flexible as to the evidence required to meet that standard.

The sample EPC contract contained a set of binding terms and conditions for the engineering and construction of the proposed facility, including provisions for: (1) a fixed price with monthly progress payments to the contractor; (2) a guaranteed schedule; (3) liquidated damages for failure to achieve (a) substantial completion by the guaranteed completion date, or (b) operation guarantees; (4) bonuses for early completion and improved performance; (5) warranties; (6) insurance; and (7) performance and facilities testing. Id. at 80. The Siting Board also reviewed USGen's preliminary plans for interconnection with the New England Power Service Company ("NEPSCo") system, but noted that the Company had not entered into a signed interconnection agreement with NEPSCo that would enable the proposed facility to have transmission access to the region. Id. at 81-82. Consequently, the Siting Board found that, upon compliance with conditions that the Company provide the Siting Board with (1) a copy of a signed EPC contract between USGen and Bechtel Power Corporation ("BPC") or a comparable entity that would provide reasonable assurance that the project would perform as a low-cost, clean power producer, and (2) a copy of a signed interconnection agreement between the Company and NEPSCo providing the proposed project with access to the regional transmission system, the Company would have established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives (Condition A). Id. at 83.

In response to Condition A, USGen presented to the Siting Board a signed EPC contract between the Company and BPC. The signed EPC contract is similar to the sample EPC contract reviewed in the underlying case and contains similar binding terms and conditions for the engineering and construction of the proposed facility. The Company also presented to the Siting Board a signed interconnection agreement with NEPSCo. The interconnection agreement provides the project with access to the regional transmission system. Accordingly, the Siting Board finds that USGen has established that its proposed project is likely to be constructed within the applicable time frames and be capable of meeting performance objectives. Further, in conjunction with the finding as to the financiability of USGen's proposed project (see USGen Decision, EFSB 96-4, at 79), the Siting Board finds that USGen has established that its proposed project meets the Siting

Board's first test of viability.

C. Operations

With respect to operation of the proposed project, the Siting Board examined whether the proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives. Id. at 85. Consistent with this objective, the Siting Board evaluated the ability of the project proponent or other reasonable entity to operate and maintain the facility in a manner which ensures a reliable energy supply. Id. at 84.

In the underlying case, the Company provided a sample O&M agreement for illustrative purposes to show the types of considerations the Company has included for comparable contracts in the past. Id. Further, the Siting Board accepted the experience of both the Company and U.S. Operating Service Company ("USOSC") in operating, maintaining, and managing comparable facilities as strong evidence that the Company would be able to negotiate an acceptable final O&M contract. Id. at 86. However, the Siting Board found that in order to establish that USGen's proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, USGen must provide a copy of a signed O&M agreement with USOSC or a comparable entity (Condition B). Id.

In response to this condition, USGen presented to the Siting Board a redacted version of a signed O&M contract between USGen and USOSC (Exh. EFSB-CF, exh.C). The O&M contract is substantially similar to the sample O&M agreement provided in the underlying case. Accordingly, the Siting Board finds that USGen has demonstrated that its proposed project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

D. Fuel Acquisition

In considering USGen's fuel acquisition strategy, the Siting Board considered whether USGen's strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project. USGen Decision, EFSB 96-4, at 86, 90. In the underlying case, the Company presented a fuel acquisition strategy that involved: (1) the intent to contract with USGen Fuel Services ("USGenFS"), an affiliated fuel supplier, for a 365 day firm natural gas supply, subject to 30 days of recall, delivered to the facility off the Tennessee Gas Pipeline mainline; and (2) a specific back-up supply plan, including a three-day, on-site oil supply transported either by truck or pipeline, with the intent to contract for fuel oil from and the ability to switch to oil for limited operation. Id. at 90. Further, in the underlying case, the Siting Board took note of an executed precedent agreement between USGen and USGenFS that provides for a firm supply to be arranged by USGenFS. Id. at 91.

In determining that the Siting Board would not require USGen to enter into a firm transportation contract for the proposed project, the Siting Board: (1) acknowledged that there is a benefit to the flexible gas procurement approach contemplated for the proposed project; (2) considered the Company's experience procuring fuel for comparable facilities and USGenFS' experience delivering fuel to comparable facilities; and (3) recognized that USGenFS, by virtue of its size and scale in the marketplace, has an enhanced ability to supply gas on a long-term basis. Id. at 91-92. However, to allow the Siting Board to monitor developments affecting gas capacity in New England, which relate to USGen's expectations as to the reliability of its fuel supply strategy, the Siting Board required USGen, prior to the commencement of construction, to provide the Siting Board with an updated assessment which reasonably confirms the continued ability of USGenFS to transport gas to the proposed project (Condition C). Id. at 92.

In response to Condition C, USGen provided the Siting Board with a natural gas supply assessment. This assessment outlined the status of gas supply projects which have a direct impact on supply availability to the proposed project (Exh. EFSB-CF(S) at 4-5). The Company also provided a list of new projects which have the potential to provide additional capacity and flexibility for buyers of gas supply in New England (Exh. EFSB-CF, exh. D).

The Siting Board finds that USGen has provided an updated assessment of natural gas supply projects targeting New England which reasonably confirms the continued ability of USGenFS to transport gas to the proposed project. Accordingly, the Siting Board finds that USGen's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the planned life of the proposed project.

Consistent with the Siting Board's conditional finding in the USGen Decision, EFSB 96-4, at 93, the Siting Board here finds that USGen has complied with (1) the condition relative to the provision of a signed O&M contract, and (2) the condition relative to the provision of documentation that reasonably confirms the continued ability of USGenFS to transport gas to the proposed project. Accordingly, the Siting Board finds that USGen has established that its proposed project meets the Siting Board's second test of viability.

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

III. ENVIRONMENTAL CONDITIONS

In the USGen Decision, we set forth six environmental conditions to be complied with during construction and operation of the proposed facility. EFSB 96-4, at 189-191. Also, we directed the Company, prior to construction, to explain its noise mitigation approach and to provide a signed copy of its certificate on its Final Environmental Impact Report ("FEIR"). Id. Accordingly, in this section, we review the Company's compliance with pre-construction conditions, and the Company's progress on complying with other environmental conditions.

A. Standard of Review

In implementing its statutory mandate to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Board requires project proponents to show that proposed facilities are sited at locations that minimize costs and environmental impacts, while ensuring a reliable energy supply. In order to determine whether such a showing is made, the Siting Board requires project proponents to demonstrate that the proposed site for the facility is superior to the noticed alternative on the basis of balancing cost, environmental impact and reliability of supply. Berkshire Power Decision, 4 DOMSB at 358; Silver City Decision, 3 DOMSB at 276; Berkshire Gas Company, 23 DOMSC 294, 324 (1991).

In the USGen Decision, the Siting Board found that, with the implementation of certain conditions, the environmental impacts of the proposed facility at the primary site would be minimized consistent with minimizing cost. EFSB 96-4, at 186-187. The Siting Board also found that the Company's primary site is preferable to the alternative site with respect to minimizing environmental impacts consistent with minimizing cost. Id. at 187.

B. Pre-Construction Directives

1. Noise Mitigation Program

In the USGen Decision, the Siting Board directed the Company to indicate, prior to construction, whether it plans to (a) incorporate noise reduction measures into a preconstruction facility design such that calculated L_{90} noise increases do not exceed 7.5 decibels, or (b) incorporate noise reduction measures in the proposed facility such that measured L_{90} noise increases do not exceed 6.0 decibels at residences (Condition H). USGen Decision, EFSB 96-4, at 157-158, 190-191.

The Company confirmed that it plans to proceed in accordance with the first option and will incorporate noise reduction measures into preconstruction facility design such that calculated L_{90} noise increases do not exceed 7.5 decibels (Exh. EFSB-CF at 8).

Accordingly, the Siting Board finds that the Company has complied with the pre-construction directive to notify the Siting Board of what noise reduction measures the Company will take in order to minimize noise impacts consistent with minimizing cost.

2. Certificate on the FEIR

In the underlying case, the Company provided a copy of the Draft Environmental Impact Report ("DEIR") (MPP-4, att. 3). At the close of the record in this case, a certificate on the FEIR had not been issued. To ensure a complete record, the Siting Board directed the Company to provide, prior to construction, a signed copy of its certificate on its FEIR. USGen Decision, EFSB 96-4, at 189.

To comply with this directive, the Company provided a certificate from the Secretary of Environmental Affairs stating that USGen's proposed project adequately and properly complies with the Massachusetts Environmental Policy Act and with its implementing regulations (Exh. EFSB-CF exh. K). Accordingly, the Siting Board finds that the Company has complied with this pre-construction directive.

C. Other Conditions

In addition to documenting its compliance with the above pre-construction directives, the Company provided information relative to its progress in complying with conditions regarding the 21G Water Withdrawal Permit (Condition E), conservation permits (Condition F), visual impacts (Condition G) and traffic impacts (Condition I).[3]

1. Chapter 21G Water Withdrawal Permit

Condition E required that the Company provide a copy of the Chapter 21G permit for the project, together with any attached conditions and an explanation of how all conditions will be met. USGen Decision, EFSB 96-4, at 132, 190.

The Company provided a copy of a 21G permit and a letter of transmittal from MDEP, and stated that the permit is now final (Exh. EFSB-CF at 4, exh. E). The 21G permit approves an effluent and river use plan consistent with that described in the USGen Decision, based on use of effluent from the Southbridge Wastewater Treatment Plant as the primary water supply for the project and on withdrawals from the American Optical Company ("AO") intake structure in Southbridge as a backup (id.). In its approval, MDEP

3 The Siting Board has also required the Company: (1) to mitigate CO_2 emissions by providing CO_2 offsets through a donation of either $370,000, to be paid in five annual installments of $74,000 during the first five years of facility operation, or $305,000 during the first year of facility operation to a cost-effective CO_2 offset program or programs to be selected upon consultation with Siting Board Staff (Condition D); and (2) to work with the Town of Charlton and the Massachusetts Highway Department ("MHD") to monitor fogging and icing in the vicinity of the proposed facility, and as necessary, to establish a plan with the identified local and state officials to ensure that any safety concerns are addressed (Condition J). USGen Decision, at EFSB 96-4, at 117-118, 189-190;169-170, 191. The Company did not submit specific information relative to these conditions.

found that diminishment of flow in the Quinebaug River as a result of project withdrawals will have a minimal effect on downstream users, even without mitigation, and further found that project withdrawals will not result in significant impacts on aquatic habitats in the river except potentially under low flow conditions (id. at 5, exh. E).

In order to mitigate for potential environmental impacts at low flow, MDEP included permit conditions to require: (1) instantaneous, real-time monitoring of flow in the Quinebaug River at a new gauging station downstream from the AO intake, with telemetering of flow data to a location manned by the Company; and (2) augmentation of flow in the Quinebaug River whenever flow reaches or falls below 0.30 cubic feet per second per square mile of tributary area (id. at exhibit E). The permit also included conditions relating to submission of an operation plan for implementing augmentation, reporting requirements, and implementation of the Company's water conservation plan (id.).

The Company indicated that, consistent with the MDEP transmittal letter, any augmentation of flow will be accomplished through releases from the United States Army Corps of Engineers ("ACOE") East Brimfield Reservoir, subject to limitations and terms of an existing agreement between ACOE and AO (id. at 6). The Company provided a letter from ACOE indicating that no separate ACOE approval is required for AO to request reservoir releases on behalf of the Company (id. at exh. F).

Accordingly, the Siting Board finds that the Company has complied with Condition E.

2. Conservation Permits

In the USGen Decision, the Siting Board noted that additional measures might be required to protect an on-site vernal pool containing marbled salamanders, a "threatened" species in Massachusetts, and that the water supply and wastewater return lines for the proposed project would traverse an area of estimated habitat for the wood turtle, a species of special concern in Massachusetts. USGen Decision, EFSB 96-4, at 133. With respect to the marbled salamanders, Condition F directed USGen to provide a copy of a conservation permit from NHESP with attached conditions and a detailed explanation of how all conditions would be met. Id. at 133, 190. Condition F also directed USGen to provide a copy of an

NHESP approval of a mitigation plan for impacts on wood turtle habitat, with an explanation of how any attached conditions would be met. Id. The Siting Board found that, with compliance with this condition, the impacts from water-related discharges and construction-related impacts of the proposed facility at the primary site would be minimized. Id. at 133.

To comply with Condition F, USGen provided the Siting Board with a copy of its final Conservation Permit from NHESP for protection of marbled salamanders (Exh. EFSB-CF, exh. H). The permit contains three conditions: (1) that USGen place 60.84 acres of land surrounding the marbled salamander vernal pool under a permanent Conservation Restriction to be held by the Charlton Conservation Commission; (2) that USGen fund a five-year study of marbled salamander movement patterns for a total of $160,000; and (3) that USGen fund and create three experimental vernal pools, at a total cost of $35,000 (id. at 1-2). Attached to the permit are a conservation plan detailing project design changes made to minimize impacts to mature forest habitat, a draft Conservation Restriction, and a prospectus for the five-year study (id., att. A, B, and C). Accordingly, the Siting Board finds that the Company has complied with Condition F relative to the marbled salamander.

With respect to the wood turtle, USGen stated that it submitted a wood turtle mitigation plan to NHESP and the Southbridge Conservation Commission as part of its Notice of Intent under the Massachusetts Wetland Protection Act regulations (id. at 7). The Company explained that under 310 C.M.R. § 10.59, the Southbridge Conservation Commission must find that the project would not have any short or long term adverse effects on the habitat of the local population of the wood turtle as a precondition of issuing an Order of Conditions (id.). The Company also explained that the NHESP does not issue a separate approval, but that NHESP submitted comments relative to the Company's Notice of Intent and such comments routinely are entitled to deference by the Conservation Commission (id.; Exhs. EFSB-CF(S) at 5; EFSB-CF(S2)). Therefore, USGen argued that the Order of Conditions issued by the Southbridge Conservation Commission on May 1, 1998 constitutes approval of a mitigation plan for the wood turtle and satisfies the Siting Board's condition on this issue (Exhs. EFSB-CF(S) at 6; EFSB-CF(S2) at 2).

To comply with Condition F, relative to the wood turtle, USGen submitted the May 1, 1998 Order of Conditions (Exh. EFSB-CF(S2)). The Order of Conditions lists 44 conditions that the Company must comply with, including five special conditions which address preservation of the wood turtle habitat (id. at 5-3D). For example, the Order of Conditions states that the Company "shall explore options to crossing Rouge Brook in a manner that would avoid both long-term and short-term construction impacts to [the] mapped wood turtle habitat" (id.). The Order of Conditions also states that "[f]ailure to comply with all conditions stated herein and with all related statutes and other regulatory matters, shall be deemed cause to revoke or modify" the Order of Conditions (Exh. EFSB-CF(S2) at 5-2). Further, the Company has provided written confirmation that it will comply with the Order of Conditions (id. at 2).

The Siting Board accepts that issuance of an Order of Conditions by the Southbridge Conservation Commission satisfies Condition F relative to the wood turtle, since the NHESP does not issue a separate approval and the Order of Conditions addresses the concerns raised by the Siting Board in the USGen Decision. Accordingly, the Siting Board finds that the Company has complied with Condition F.

3. Notice of Visual Impact Mitigation Requirement

Condition G required the Company to develop and implement an off-site shrub and tree plantings or window awnings plan. In this regard, the Siting Board stated that the Company: (1) shall provide shrub and tree plantings or window awnings on private property, only with the permission of the property owner, and along public ways, only with the permission of the appropriate municipal officials; (2) shall provide written notice of this requirement to public officials in Charlton and to all affected property owners prior to the commencement of construction; (3) may limit requests from local residents and town officials for mitigation measures to a specified period ending no less than six months after initial operation of the plant; (4) shall complete all such mitigation measures within one year after completion of construction, or if based on a request after commencement of construction, within one year after such request; and (5) shall be responsible for the reasonable maintenance or replacement plantings as necessary to ensure that health plantings become established. In addition, the Siting Board directed USGen to make available to affected Harrington Road residents the option of at least one strategically placed planting of 20 feet or more as may be practical and appropriate to the setting, in lieu of a row of several smaller plantings. USGen Decision, EFSB 96-4, at 140, 190.

The Company provided the text of a letter and attachment to be used for purposes of notifying property owners and officials concerning the requirement for off-site visual impact mitigation (Exhs. EFSB-CF at exh. I; EFSB-CF(S) at exh. 6). The Company stated that, after acceptance of its pre-construction compliance filing by the Siting Board but prior to beginning construction, it will send the notice to all property owners within one mile of the facility and to all residents on Harrington Road. In addition, the Company will send the notice to the Charlton Board of Selectmen, with a request that the notice be posted in Charlton Town Hall.

Accordingly, the Siting Board finds that the Company has developed an acceptable letter for notifying property owners and officials concerning the Company's required off-site visual mitigation.

4. Traffic Mitigation

Condition I required USGen to develop and implement a traffic mitigation plan which includes the scheduling of the delivery of fuel oil, materials, and equipment to avoid peak daily travel periods, or route modifications or other appropriate measures, excluding capital improvements, to minimize traffic-related impacts along likely access routes to the site including Route 20 and Route 169. USGen Decision, EFSB 96-4, at 164, 191. Further, the Siting Board directed the Company to consult with the towns of Auburn, Oxford, Sturbridge, and Charlton. Id.

The Company indicated that it has consulted with officials of the towns of Auburn, Oxford, Sturbridge and Charlton, and provided a summary of the consultation with notes from its meeting with each town (Exh. EFSB-CF at 8, exh. J). The Company also provided a description of its "general approach" for managing traffic impacts with respect to the four towns based on its consultation (Exh. EFSB-CF(S) at 1-2).

As part of its general approach for traffic mitigation, the Company has committed to: (1) develop and issue specific delivery instructions with purchase orders, including such matters as routing, delivery hours and on-site check-in location; (2) in cooperation with the EPC contractor, specifically coordinate with Town Engineer or Highway Department designees concerning oversized or heavy loads; (3) install temporary gravelled areas to assist with removal of mud from tires before vehicles depart from the site onto Route 169; and (4) hold additional meetings with Town of Charlton officials to further address delivery schedules of major equipment and provide a forum for discussing ongoing traffic management matters (id.).

Accordingly, the Siting Board finds that the Company has made appropriate progress relative to the development and implementation of its general approach for traffic mitigation.

IV. ADDITIONAL ISSUES

The Siting Board requires that project proponents notify the Siting Board of any changes other than minor variations to the proposal as presented to the Siting Board, so that it may decide whether to inquire further into such issues. USGen Decision, at 191-192. In addition to the compliance issues addressed above, USGen also provided the Siting Board with information concerning two changes to the project as described in the USGen Decision: (1) changes to the facility layout for the project, and (2) the use of a fixed roof tank, rather than a floating roof tank, to store aqueous ammonia.

A. Facility Layout Changes

USGen indicated that it had altered the facility layout to accommodate a multiple shaft configuration, rather than the single shaft configuration originally proposed (Exh. EFSB-CF at 8). The Company explained that in a single shaft configuration, both the steam turbine and the combustion turbine are connected to a single generator, while in a multiple shaft configuration, the steam turbine and combustion turbines each have a dedicated generator; however, the total output of the steam and combustion turbines remains the same (id.). The

Company indicated that it decided to use the multiple shaft configuration because Westinghouse is much further along in the design of that configuration; use of the single shaft configuration could have delayed the project by six months to one year (id. at 9).

USGen also noted that it made minor modifications to the original plant layout to protect the habitat of the marbled salamander (id.).

USGen indicated that the layout changes necessitated by the use of the multiple shaft configuration would have no impact on the noise, water consumption, or air emissions of the proposed project (id. at 8). The Company also indicated that the design change would not impact marbled salamander habitat, and provided maps showing the site plan as previously designed, and as currently proposed (Exh. EFSB-CF(S) at 2, exhs. 1, 2, and 3).

The Siting Board has reviewed the information provided by USGen regarding the proposed changes in facility layout, and finds that they are minor and will not affect the environmental impacts of the proposed project as discussed in the USGen Decision, with the exception of impacts to the marbled salamander. The Siting Board also finds that the new facility layout will reduce impacts on the habitat of the marbled salamander. Accordingly, the Siting Board finds that the changes in the layout of the proposed facility do not require further inquiry.

B. Ammonia Tank

USGen noted that, in previous filings, it had erroneously indicated that a floating roof tank would be used for ammonia storage (Exh. EFSB-CF at 9). The Company indicated that its intent always had been to use a fixed roof tank, which vents ammonia vapors back to the tanker truck during filling, rather than a floating roof tank (id.). The Company stated that the fixed roof tank provides a more reliable, leak-tight enclosure than a floating roof tank, and that the two types of tanks are equally safe for plant personnel and the public (Exh. EFSB-CF(S) at 3). The Company also noted that the fixed roof tank is similar in design to tanks used at other USGen facilities (Exh. EFSB-CF at 9).

The Siting Board finds that the use of a fixed roof, rather than a floating roof, tank for the storage of aqueous ammonia should not degrade the safety of the proposed project.

Accordingly, the Siting Board finds that the change from a floating roof to a fixed roof tank does not require further inquiry.

V. DECISION

In the USGen Decision, the Siting Board found that upon compliance with the conditions set forth therein, the construction of the proposed generating facility is consistent with providing a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost. EFSB 96-4, at 188.

Here, the Siting Board has found that USGen has demonstrated that its proposed project is likely to be a viable source of energy. Further, the Siting Board has found that the Company has complied with all pre-construction conditions and, therefore, USGen is authorized to commence construction of its proposed facility. In addition, USGen has fully complied with Condition E concerning the Chapter 21G Water Withdrawal Permit and Condition F concerning the conservation permits. Therefore, we find that with the implementation of Conditions D, G, H, I and J concerning the issues of CO_2 mitigation, visual mitigation, noise mitigation, traffic mitigation and safety, respectively, the proposed facility will provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In addition, consistent with the Siting Board's directive to USGen to inform the Siting Board of any changes to USGen's proposed project, other than minor variations, USGen has informed the Siting Board of two such changes. The Siting Board has found that neither of these changes requires further inquiry.

Jolette A. Westbrook
Hearing Officer

Dated this 20th day of May, 1998

Unanimously APPROVED by the Energy Facilities Siting Board at its meeting of May 20, 1998 by the members and designees present and voting. Voting for approval May 20, 1998 of the Tentative Decision On Compliance as amended: Janet Gail Besser, (Chair EFSB\DTE); James Connelly (Commissioner, DTE); W. Robert Keating (Commissioner, DTE); Sonia Hamel (for Trudy Coxe, Secretary, Executive Office of Environmental Affairs); and David L. O'Connor (for David A. Tibbetts, Director, Department of Economic Development).

Janet Gail Besser

Janet Gail Besser
Chair

Dated this 20th day of May, 1998

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).