COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Board

In the Matter of the Petition of ANP Blackstone Energy Company for Approval to Construct a Bulk Generation Facility and Ancillary Facilities in Blackstone, Massachusetts	)	EFSB 97-2
In the Matter of the Petition of ANP Blackstone Energy Company and Boston Edison Company for Approval to Construct Two 1.1 Mile 345 kV Overhead Transmission Lines and Ancillary Facilities in Blackstone and Mendon, Massachusetts	)	EFSB 98-2

FINAL DECISION

M. Kathryn Sedor
Hearing Officer
January 14, 1999

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TABLE OF CONTENTS

LIST OF ABBREVIATIONS

Abbreviation	Explanation
AALs	Annual allowable ambient limits
ABB	Asea Brown Boveri, Inc.
ACEC	Area of Critical Environmental Concern
AFB	Atmospheric fluidized bed coal technology
Algonquin	Algonquin Gas Transmission Company
ANP	ANP Blackstone Energy Company
BACT	Best available control technology
BECo	Boston Edison Company
Blackstone	Town of Blackstone
Btu/kwh	British thermal units per kilowatt hour
BVCEP	Blackstone Valley Citizens for Environmental Preservation
BVW	Bordering Vegetated Wetlands
CAAA	Federal Clean Air Act Amendments of 1990
Cabot	Cabot Power Corporation
CC	Combined Cycle
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 Blackstone Energy Company
Companies	ANP and BECo
CT	Generation Combustion Turbine
CRWA	Charles River Watershed Association
dBA	A-weighted Decibel
DEIR	Draft Environmental Impact Report
DOE	The United States Department of Energy
DOT	The United States Department of Transportation
$/kWh	Dollars per kilowatt-hour
$/MWh	Dollars per megawatt-hour
DSM	Demand side management
EIR	Environmental Impact Report
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
GCC	Gas-fired combined cycle unit
GEP	Good Engineering Practice
GIS	Geographic Information Systems Mapping
gpd	Gallons per day
GTF	NEPOOL Generation Task Force
GWPD	Groundwater protection district
HRSG	Heat recovery steam generator
IDC	IDC Bellingham LLC
IDLH	Immediately Dangerous to Life or Health
IPP	Independent power producer
IRR	Internal Rate of Return
Kimball	Kimball Sand and Gravel
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

MassGIS	Massachusetts Geographic Information System
MA WMA	Massachusetts Water Management Act
MDEM	Massachusetts Department of Environmental Management
MDEP	Massachusetts Department of Environmental Protection
Mendon	Town of Mendon
mG	Milligauss
mgd/mi^2	million gallons per day per square mile
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
ORW	Outstanding resource water
OSP	Ocean State Power
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
RFP	Request for Proposals
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
SOx	Sulfur oxides
SPCCP	Spill Prevention, Control and Countermeasure Plan
TAG	EPRI Technical Assessment Guide
TELs	Threshold effects exposure limits
Town	Town of Blackstone
tpy	Tons per year
USGS	United States Geological Survey
USGS Study	1991 Report by USGS, Water Resources and Aquifer Yields in Charles River Basin, Massachusetts
USFS	United States Forest Service
VOCs	Volatile organic compounds
WRG	Wrentham Research Group
WWTF	Waste Water Treatment Facility
ZBA	Zoning Board of Appeals

The Energy Facilities Siting Board ("Siting Board") hereby APPROVES subject to conditions (1) the petition of ANP Blackstone Energy Company to construct a nominal net 580-megawatt bulk generating facility and ancillary facilities at the proposed site in Blackstone, Massachusetts, and (2) the joint petition of ANP Blackstone Energy Company and Boston Edison Company to construct two new 1.1 mile long 345 kV overhead transmission lines in the Towns of Blackstone and Mendon, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Facilities

1. The Proposed Generating Facility

ANP Blackstone Energy Company ("ANP" 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 Blackstone, Massachusetts ("Blackstone") ("generating facility") (Exh. BLK-1, at 1-1). The generating facility would be located on approximately 31 acres of a 157-acre parcel of previously disturbed land in the northeast corner of Blackstone, along the Blackstone-Mendon town line (id.; Exh. BLK-12.4, at 2-1; Tr. 5, at 57).

The Company has proposed to deliver natural gas to the generating facility via a new 12-inch pipeline, approximately 7,000 feet in length (Exh. BLK-12.4, at 3-10). The pipeline would be constructed by Tennessee Gas Pipeline Company ("Tennessee"), and would extend from Tennessee's existing pipeline facility in the Town of Mendon ("Mendon") to the project site in Blackstone (id.). Electric power generated by the proposed project would be delivered via two new overhead 345 kV transmission lines, approximately 1.1 miles in length, that would interconnect with an existing Boston Edison Company ("BECo") 345 kV line in Mendon (Exh. BLK-BE-14, at 1-3; Tr.-J-1, at 77).

The generating facility 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 (Exh. BLK-1, at 1-6). 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 (Exhs. BLK-12.4, at 3-26; BLK-12.2, at 3-22).

The generating facility 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 (Exh. BLK-1, at 1-6,7). Each combustion turbine will generate approximately 180 MW of electricity (210 MW with steam injection), 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 injection) (id.).[1]

The proposed site for the generating facility is located within a residentially zoned area of Blackstone (Exh. HO-EL-9.1). The site consists of vacant, previously mined land within a larger, active sand and gravel quarry (Exh. BLK-12.2, at 3-1). The site is bounded to the north by the Blackstone-Mendon town line and a residential neighborhood in Mendon; to the northwest by the Mill River and a residential neighborhood in Blackstone; and to the northeast by property owned by the Town of Blackstone (id. at 3-2). The site is bordered on all other sides by the sand and gravel operation (id.)

The proposed generating facility would cost approximately $300 million in year 2000 dollars, inclusive of interconnection costs (Exh. HO-C-1).

ANP Blackstone is a wholly-owned subsidiary of American National Power, Inc. (Exh. 1-1, at 1-3). American National Power, Inc. is an affiliate of National Power, plc, ("NP") which is the leading electric power generating company in the United Kingdom and owns

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[1] The facility has a design output of 616 MW at 20 degrees Fahrenheit, 579 MW at 59 degrees Fahrenheit, and 534 MW at 90 degrees Fahrenheit, assuming the use of air cooled condensers and steam augmentation (Exh. BLK-1, at 1-1, n.2). Without steam augmentation, facility output would be approximately 35 MW lower at each temperature condition (id.).

and/or operates approximately 24,100 MW of generating capacity world-wide, including six independent power projects in the United States totaling 1,536 MW of generating capacity (id.).

2. The Proposed Transmission Facilities

ANP Blackstone and BECo (collectively "Companies") have proposed an electrical interconnection for the generating facility that would consist of two 1.1 mile 345 kV overhead transmission lines, and a new substation on the generating facility site (Exh. BLK-BEC-14, at 1-1 to 1-3; Tr. 1, at 77). The transmission lines would interconnect the generating facility with an existing BECo 345 kV transmission line ("Line 336") approximately one mile away on a BECo right-of-way ("ROW") in Mendon (Exh. BLK-BEC-14, at 1-1).

The proposed transmission lines would create a "loop" interconnection between the proposed generating facility and Line 336 (id. at 1-3). The transmission lines would begin at a break point in Line 336 in Mendon, and then would run on a new set of wooden H-frame structures to the proposed substation on the generating facility footprint (id. at 1-6). The transmission lines would return from the generating facility to the Line 336 break point in Mendon on a second set of new wooden H-frame structures (id.). The Companies propose to locate both sets of H-frame structures, as well as the natural gas interconnection, within a new 300-foot wide utility corridor (id.). The estimated cost of the proposed transmission facilities is $10.5 million (id. at 1-10).

ANP Blackstone and BECo also have noticed an alternative electrical interconnection for the generating facility that would consist of a double radial transmission interconnection within a variable-width corridor, with both overhead and underground segments, and a new substation on the BECo ROW in Blackstone (id. at 1-10 to 1-11 and Fig. 1-4; Exh. BLK-BEC-18, at 10-6 to 10-8). The estimated cost of the alternative transmission facilities is $16.9 million (id. at 1-11).

B. Jurisdiction

1. The Proposed Generating Facility

The Company's petition to construct a bulk generating 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 a project applicant 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. G. L. c. 164, § 69H; G.L. c. 164, § 69J.

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.

G.L. c. 164, § 69G.

At the same time, the Company's proposal to construct utility connections and other related 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.

Id.

2. The Proposed Transmission Facilities

The Companies' petition to construct the proposed electrical transmission facilities was filed in accordance with G. L. c. 164, § 69H, which requires the Siting Board to implement the energy policies in its statute so as to provide a reliable 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 a project applicant to obtain Siting Board approval for construction of proposed facilities, other than generation facilities, at a proposed site before another state agency may issue a construction permit for the facilities.[2]

The proposed electric interconnection falls squarely within the second definition of "facility" set forth in Section 69G, which states 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 . . .

G. L. c. 164, § 69G.[3]

The electric interconnection also falls within the third definition of facility set forth in G. L. c. 164, § 69G, since it would be "an integrated part of the operation of" the generating facility.[4]

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[2] G. L. c. 164, § 69H, as amended by the Acts of 1997, c. 164, § 204; G. L. c. 164, § 69J, as amended by the Acts of 1997, § 209. Chapter 164 of the Acts of 1997, enacted November 25, 1998 ("Electric Restructuring Act") included a number of substantive amendments to the Siting Board's statutes. ANP Blackstone's generating facility petition was filed pursuant to, and the proposed generating facility is subject to review under, the version of these statutes in effect prior to enactment of the Electric Restructuring Act. See, St. 1997, § 310. The Companies' transmission line petition was filed after enactment of the Electric Restructuring Act, and after the effective date of the relevant amendments to the Siting Board's statutes. Accordingly, the transmission line project is reviewable under the statutes as amended. Id; St. 1997, § 342. Unless expressly noted otherwise, the statutory citations used in this Decision reference the version of the Siting Board's statutes in effect prior to enactment of the Electric Restructuring Act.

[3] As amended by St. 1997, § 202.

[4] Id.

C. Procedural History

On July 15, 1997, ANP filed with the Siting Board[5] a petition to construct and operate a nominal net 580-megawatt natural gas-fired, combined-cycle power plant and ancillary facilities in the Town of Blackstone, Massachusetts. The Siting Board docketed the petition as EFSB 97-2.

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 III.A.1, below).

On September 25, 1997, the Siting Board conducted a public hearing in Blackstone. 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 the Town of Mendon ("Mendon"); Northeast Energy Associates ("NEA"); Ocean State Power ("OSP"); the Wrentham Research Group ("WRG"); and the Blackstone Valley Citizens for Environmental Preservation ("BVCEP"). Six timely petitions to intervene were filed by individual members of the BVCEP (collectively "Individuals"): Dennis J. and Anita R. Burd ("Burds"); Peter M. Confrey; Philip J. Cieply; Kathleen M. Coffey-Daniels; Catherine M. and Donald E. Mock ("Mocks"); and Kathleen E. Tardiff.

Timely petitions to participate as an interested person were filed by Josephine Beauchamp; Tami Chassie; Cabot Power Corporation ("Cabot"); Paul D'Orazio; Robin L. Fletcher; John M. Fortunato; Patricia Graham; Daniel P. and Paula L. Gray ("Grays"); Richard A. and Denise C. Levesque ("Levesques"); Patricia LoTurco; Nancy J. and Reginald J. Macari ("Macaris"); and Janice Zych.

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[5] Prior to September 1, 1992, the Siting Board's functions were effected by the Energy Facilities Siting Council ("Siting Council"). See St. 1992, c. 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.

ANP filed opposition to the petitions of NEA, OSP, WRG, the BVCEP and the Individuals.

The Hearing Officer granted the petitions to intervene filed by Mendon and the BVCEP (Hearing Officer Procedural Order, December 9, 1997). The petitions of the Individuals were denied without prejudice, to allow for their collective representation by the BVCEP. Interested person status was granted to Josephine Beauchamp, Tami Chassie, Cabot, Robin Fletcher, John Fortunato, Patricia Graham, the Grays, the Levesques, Patricia LoTurco, the Macaris, Paul D'Orazio, and Janice Zych. The Hearing Officer denied the petitions to intervene of NEA, OSP and WRG. NEA and OSP were granted status as interested persons (id.).

Mendon and the BVCEP subsequently entered into settlements with the Company and formally filed withdrawals from the proceeding on April 1, 1998 and March 31, 1998, respectively.

On March 20, 1998, ANP and BECo jointly filed with the Siting Board a "Supplemental Filing" in EFSB 97-2. The Supplemental Filing presented a new preferred route for the proposed generating facility's electrical interconnection. This new route was approximately 1.3 miles in length and therefore jurisdictional.[6] Accordingly, the Supplemental Filing was assigned an independent docket number, EFSB 98-2.

The Siting Board conducted eleven days of evidentiary hearings in the generating facility docket, commencing on April 1, 1998 and ending on May 6, 1998. Evidentiary hearings relative to the electrical interconnection component of the generating facility project were reserved until such time as they could be held jointly with the evidentiary hearings in EFSB 98-2. 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")

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6 The Supplemental Filing estimated a route length of approximately 1.3 miles (Exh. BLK-BEC-14, at 1-3). The most recent route length estimate is 1.1 miles (Tr. 1, at 77).

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 ANP, who testified as to viability, cost and steam augmentation issues; Daniel Lorden, project director of ANP, who testified as to interconnection issues; Robert Kasle, manager of fuel procurement for ANP, 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; George S. Lipka, senior project manager for Earth Tech, who testified as to air impacts; David Keast, an independent acoustical engineer, who testified as to noise impact and noise mitigation issues; Pamela Chan, project manager for Earth Tech, who testified as to traffic, visual, wetlands and other environmental issues; and Richard Friend, hydrologist for Earth Tech, who testified on water resource issues.

On June 24, 1998, ANP submitted its brief in EFSB 97-2, except with respect to those issues pertaining to the electrical interconnect.

The Siting Board conducted two public hearings in EFSB 98-2, the docket pertaining to the Companies' proposed electrical interconnection. The first hearing was held in Mendon on June 9, 1998, and the second was held in Blackstone on June 11, 1998. A timely petition to intervene in 98-2 was filed by IDC Bellingham LLC ("IDC"), which ANP opposed. The Hearing Officer denied IDC's petition to intervene, but granted IDC status as an interested person.

The joint EFSB 97-2/98-2 transmission line hearings were held on September 29, 1998 and October 1, 1998.[7] ANP and BECo presented the testimony of six witnesses: Robert Charlebois, project manager for ANP; Steven Pedrick, construction project manager for ANP; Pamela Chan, senior program director at Earth Tech, who testified regarding site selection and environmental issues; Paul F. Barry, senior engineer at BECo, who testified regarding

[7] For purposes of this decision, the transcripts from the joint hearings held in 97-2/98-2 on September 29 and October 1, 1998, will be designated as Tr.-J-1 and Tr.-J-2, respectively.

engineering aspects of the interconnection facilities and the BECo transmission system; Hantz Presume, senior engineer at BECo, who testified regarding the New England Power Pool ("NEPOOL") and the reliability of aspects of the interconnection facilities; and William H. Bailey, Ph.D., president and head scientist of Bailey Research Associates, Inc., who testified regarding the electric and magnetic field effects of the interconnection facilities and the potential health-related impacts of such fields. ANP and BECo submitted their joint brief with respect to the transmission facilities on October 22, 1998.

On October 26, 1998, EFSB 97-2 and EFSB 98-2 were consolidated by the Hearing Officer for decision.

The Hearing Officer entered 828 exhibits into the record in the consolidated cases, consisting primarily of information request responses and record request responses. The BVCEP entered 174 exhibits into the record, and Mendon entered 96 exhibits into the record. ANP and BECo collectively entered 42 exhibits into the record.[8]

D. Scope of Review

1. The Proposed Generating Facility

In accordance with G.L. c. 164, §§ 69H and 69J, before approving a petition to construct a generating facility, the Siting Board requires an applicant to justify its proposal as follows. First, the Siting Board requires the applicant to show that additional energy resources are needed. Cabot Power Corporation, EFSB 91-101A at 5 (1998) ("1998 Cabot Power Decision"); ANP Bellingham Energy Company, EFSB 97-1, at 6 (1998) ("ANP Bellingham 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. 1998 Cabot Power

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8 Included among the exhibits entered into the record in the consolidated cases was certain evidence from the record in ANP Bellingham Energy Company, EFSB 97-1 (August 18, 1998), including nine of the transcript volumes (Tr. 10, at 5-9).

Decision, EFSB 91-101A at 5; ANP Bellingham Decision, EFSB 97-1, at 6; 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. 1998 Cabot Power Decision, EFSB 91-101A at 5; ANP Bellingham Decision, EFSB 97-1, 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. 1998 Cabot Power Decision, EFSB 91-101A at 6; ANP Bellingham Decision, EFSB 97-1, at 6; NEA Decision, 16 DOMSC at 343 (see Section III.A, below).

In the present case, the Siting Board allowed ANP Blackstone to withdraw its noticed alternative site.[9] Consequently, ANP must demonstrate that its proposed facility's 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, ANP 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

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[9] 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"). This legal and policy analysis served as the basis for granting of ANP's request to withdraw its noticed alternative site in this proceeding. See, ANP Blackstone Energy Company, EFSB 97-2, Hearing Officer Procedural Order (December 16, 1997).

conflicting environmental concerns as well as among environmental impacts, cost and reliability (see Section III.A, below).

2. The Proposed Transmission Facilities

In accordance with G.L. c. 164, §§ 69H and 69J[10], before approving an application to construct transmission facilities, the Siting Board requires applicants to justify its proposal in three phases. First, the Siting Board requires the applicant to show that additional energy resources are needed (see Section IV.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 IV.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 the noticed alternative in terms of cost, environmental impact, and reliability of supply (see Section IV.C, below).[11]

[10] As amended by St. 1997, c. 164, § 204.

[11] 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 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 purposes of the proceeding.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, § 69H, the Siting Board is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. 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. 1998 Cabot Power Decision, EFSB 91-101A at 8; ANP Bellingham Decision, EFSB 97-1, 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. 1998 Cabot Power Decision, EFSB 91-101A at 8; ANP Bellingham Decision, EFSB 97-1, 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 10; 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,[12] but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. 1998 Cabot Power Decision, EFSB 91-101A at 9; ANP Bellingham Decision, EFSB 97-1, 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. 1998 Cabot Power Decision, EFSB 91-101A at 9; ANP Bellingham Decision, EFSB 97-1, 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

12 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 1994 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")[13] 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.[14]

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13 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.

14 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

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. 1998 Cabot Power Decision, EFSB 91-101A at 11; ANP Bellingham Decision, EFSB 97-1, at 11-12; 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 ANP's analysis of the need for the updated project for reliability 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 1998 Cabot Power Decision, EFSB 91-101A at 11; ANP Bellingham Decision, EFSB 97-1, at 12; 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 updated facility during the 2000 to 2006 time period.

Siting Board for this same reason in Attorney General v. Energy Facilities Siting Board, 419 Mass. 1003 (1995) ("Attorney General").

a. New England

ANP asserted that there is a need for at least 580 MW[15] of additional energy resources in New England beginning in the year 2000 and beyond (Exh. BLK-1, at 1-21). 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") forecast and other data published by NEPOOL (Exhs. HO-N-34m.8 through HO-N-34m.14).[16] The Company indicated that it combined its demand and supply forecasts to produce a series of need forecasts (Exh. BLK-1, at 2-21).

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 2-3). The Company stated that it developed an adjusted summer peak load forecast 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 (Exh. BLK-1, at 2-9 to 2-10).

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15 The Company indicated that the updated project's summer capacity rating with steam augmentation is 534 MW, its winter capacity rating with steam augmentation is 616 MW, and its nominal average rating is 579 MW (Exh. BLK-1, at 2-21, n.30). The Company stated that it assessed the need for 534 MW, the summer peak load, because the reliability need is more acute in the summer season than in the winter season ((Exh. EFSB-1, at 80, 84). In Section II.A.2.a.(3) below, the Siting Board evaluates the need for 580 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.

16 The Company initially relied on the 1996 and 1997 CELT forecasts (Exhs. BLK-1, at 2-5; HO-N-1; HO-N-2). During the course of the proceedings, NEPOOL issued the 1998 CELT report. ANP indicated that the 1998 CELT report projects a higher summer peak load than the 1997 CELT report (see Exh. HO-N-3(S)). For purposes of this analysis, the Siting Board will focus on the 1998 CELT report.

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 1998 CELT report (Exhs. HO-N-34h.2; HO-N-2.2).

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-34h.2; HO-N-2.2).

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-N-34h.2; HO-N-2.2). 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 (Exh. EFSB-1, at 17). The Company asserted that the reference forecast provides a reasonable projection of regional demand (id.).[17] The Company also presented CELT report high case

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[17] 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 NEPOOL has prepared a new short-run and long-run load forecast for the 1998 CELT report (Exh. HO-N-3(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.).

("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. BLK-1, at 2-29 to 2-30, App. F).[18,19]

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;[20] (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. BLK-1, at 2-9; HO-N-34h.2). 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. BLK-1, at 29).

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 (1) 1998 CELT report forecast of NUG netted from load, and (2) three forecasts of DSM savings (Exh. HO-N-34h.2). Thus, the Company presented three forecasts of adjusted summer peak load based on the 1998 CELT forecast report.

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18 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. BLK-1, at 2-9).

19 The Company provided the 1996 CELT report high and low case (Exh. BLK-1, at 2-29 to 2-30). The 1997 CELT report is the same as the 1996 CELT report in the long run (see n.17, above). The 1998 CELT report does not include a high or low case (Exh. HO-N-2.2, at 1).

20 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 1998 CELT report's projections of peak load and energy savings from DSM are lower than the projections in the 1997 CELT report beginning in 2002 in the summer, and for all years in the winter (id.).

(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. 1998 Cabot Power Decision, EFSB 91-101A at 15; ANP Bellingham Decision, EFSB 97-1, 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 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.[21] As noted above, NEPOOL assigns a low probability of occurrence to each of these forecasts. Consistent with previous Siting Board decisions (see, e.g., 1998 Cabot Power Decision, EFSB 91-101A at 15; ANP Bellingham Decision, EFSB 97-1, at 16; 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., 1998 Cabot Power Decision, EFSB 91-101A at 16; ANP Bellingham Decision,

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21 As indicated above, the 1998 CELT report does not contain high and low load forecast scenarios; the Siting Board therefore relies on the 1997 CELT high and low load forecast scenarios.

EFSB 97-1, at 16-17; 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 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 by ANP, 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 1998 Cabot Power Decision, EFSB 91-101A at 16-17; 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 summary, 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 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 1998 CELT report (Exhs. BLK-1, at 2-10; HO-N-34l.5). 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-34l; HO-N-3(S)).[22] Specifically, beginning in 2000, the Company deducted the capacity of: (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, and 5 Units (92 MW) (Exhs. HO-N-34l.6; HO-N-34l.7). ANP also added the capacity of: (1) the Wyman 1-3 units (223 MW); and (2) the Devon 11-14 units (125 MW),[23] both of which consist of combustion turbines recently granted permanent operating permits (Exhs. HO-N-34l.6;

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22 ANP listed the most notable changes from the 1997 CELT forecast: (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-3(S); HO-N-2.2).

23 The Devon 11-14 units were added beginning in the year 2001 (Exhs. HO-N-34d; HO-N-34l.6; HO-N-34l.7).

HO-N-34l.7).

The Company stated that, to reflect uncertainties in future capacity in its supply scenarios, it then adjusted the 1998 CELT 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. BLK-1, at 2-10 to 2-21; HO-N-34l). 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. BLK-1, at 2-10). Specifically, the Company stated that the 1998 CELT forecast 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 2-11, 2-16 to 2-17).

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 (id. at 2-13 to 2-14; Exh. HO-N-8.1). ANP 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 (Exhs. HO-N-8.1; HO-N-8.2). ANP argued that it is increasingly likely that the Millstone 1 unit will be retired (Exhs. HO-N-8.2; H-N-34g). 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 (Exh. HO-N-8.2).

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. BLK-1, at 2-17).[24] 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.). ANP also noted that these units may experience performance degradation due to their age (id. at 2-16).

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 (Exhs. HO-N-34f; HO-N-34l).[25] 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-3(S); HO-N-34l.6; HO-N-34l.7). The Company also indicated that two new proposed generating facilities have reached significant licensing milestones: Tiverton, Rhode Island (250 MW), and Millennium (360 MW) (Exhs. HO-RR-5; EFSB-6).[26]

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 (386 MW in the year 2000

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24 ANP indicated that Phase II of the CAAA will require additional nitrogen oxides ("NOx") reductions to be implemented by 1999 (Exh. BLK-1, at 2-17).

25 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 (Exhs. BLK-1, at 2-19; HO-N-11).

26 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 (Exhs. BLK-1, at 2-19; EFSB-1, at 58 to 61).

increasing to 908 MW in 2006)[27] (Exhs. HO-N-9.1; HO-N-341.7). In addition, the Company added 50 percent of the capacity of new generating units that have reached significant licensing completion (305 MW) (Exhs. BLK-1, at 2-20; HO-N-341.6; HO-N-341.7).

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); 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. BLK-1, at 2-17 to 2-18; HO-N-341.5; HO-N-341.7). 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); 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. BLK-1, at 2-17; HO-N-341.5; HO-N-341.7).

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" (Exhs. BLK-1, at 2-9; EFSB-1, at 76-77). ANP stated that, in that document, NEPOOL specifies required reserve margins of 15 percent of adjusted peak load (Exh. BLK-1, at 2-9).[28]

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27 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. BLK-1, at 2-18, n.22) (citing Berkshire Power Decision, 4 DOMSB at 270). 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.).

28 ANP 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. EFSB-1, at 72, 73).

(b) Analysis

The Company has presented a base supply scenario which was based on the 1998 CELT report supply forecast and 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 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: 386 MW in 2000 increasing to 908 MW in the year 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 are 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, 1998 Cabot Power Decision, EFSB 91-101A at 22; ANP Bellingham Decision, EFSB 97-1, at 23; Berkshire Power Decision, 4 DOMSC at 270. The capacity reduction assumed for the Company 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 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 its 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. This assumption 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 2000 and reasonably assumed that the reserve margins would remain at the values projected for the year 2000 in the years 2001 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 (Exh. HO-N-34m.8). All nine of these need forecasts demonstrate a sustained need for at least 580 MW of capacity in the year 2000 (id.). See Table 1, below.

Table 1

RANGE OF REGIONAL NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1998 CELT	High	(965)	(2,020)	(3,460)
1998 CELT	Base	(1,136)	(2,192)	(3,632)
1998 CELT	Low	(1,308)	(2,364)	(3,804)

Source: Exh. HO-N-34m.8.

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 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 need forecasts based on the 1998 CELT summer peak load forecast for the year 2000 are shown in Table 1, above. All nine need forecasts demonstrate a sustained need for at least 580 MW of capacity in 2000. Accordingly, the Siting Board finds 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.

b. Massachusetts

The Company asserted that there is a need for new capacity in Massachusetts by the year 2000 (ANP Brief at 27). 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. BLK-1, at 2-23 to 2-25; HO-N-2.2, at 1; HO-N-34m.12 to 34m.14). The Company stated that it then combined its demand and supply forecasts to produce a series of need forecasts (Exh. BLK-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 1998 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. at 2-24; Exhs. HO-N-2.2; HO-N-34m.12 to 34m-14). 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 (Exh. BLK-1, at 2-24). 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-5). 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. BLK-1, at 2-24).

(b) Analysis

In its Massachusetts need analysis, ANP provided base case demand forecasts for adjusted 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 forecasts presented in the

[29] ANP 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 (Exhs. BLK-1, at 2-24; EFSB-1, at 80).

regional need analysis. In addition, 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.(1), 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.(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 the generating resource ownership and commitments of the Massachusetts electric utility companies (Exh. BLK-1, at 2-24).

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 2-24 to 2-25; Exhs. EFSB-6). 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 (Exh. BLK-1, at 2-24). 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 (id. at 2-25).

The Company stated that it assumed the same yearly percentage reserve margin requirements for Massachusetts as were assumed for the region (id. at 2-24). The Company applied the percentages 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 supply 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

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30 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-17.1).

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 the three supply forecasts (Exhs. HO-N-34m.8 through 34m.14). Of these nine summer need forecasts, all demonstrate a sustained need for at least 580 MW of capacity in the year 2000. See Table 2, below.

Table 2

RANGE OF MASS NEED CASES

2000

Demand Case	DSM	High Supply	Base Supply	Low Supply
1998 CELT	High	(1,305)	(1,566)	(1,921)
1998 CELT	Base	(1,386)	(1,647)	(2,002)
1998 CELT	Low	(1,468)	(1,728)	(2,084)

Source: Exh. HO-N-34m.8

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 the year 2000, 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 year 2000 are shown in Table 2, above. All such summer need forecasts show a sustained need for at least 580 MW in the year 2000. Accordingly, the Siting Board finds 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.

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[31] 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. BLK-1,

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31 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. BLK-1, at 2-28 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.

at 2-28). 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 (Exh. EFSB-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[32] for the 5-year period, 2000 through 2004, that 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. BLK-1, at 2-28 to 2-29; HO-N-34t.1). The Company stated that these analyses demonstrate that the proposed facility 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. BLK-1, at 2-30).

The Company explained 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;[33]

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32 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 (Exh. EFSB-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-N-34o). The Company noted that in a deregulated market, producers will need to cover these costs with revenues resulting from market clearing price payments (id.).

33 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. BLK-1, at 2-29). 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.).

(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;[34] (5) classification of specific units as must-run;[35](6) addition of new generic capacity to meet projected regional capacity requirements; (7) fuel price forecasts;[36] and (8) operating characteristics of the proposed facility[37] (id. at 2-28 to 2-30; Exhs. HO-N-34m.2; HO-N-34t.1). The Company noted that SO_2 allowance costs were explicitly incorporated into the economic dispatch (Exh. HO-N-34t.1).

The Company calculated energy efficiency savings for the years 2000 through 2004 based on meeting projected regional capacity requirements with generic combustion turbine

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34 The Company stated that data on capacity, heat rates, fuel types, O&M costs, and availability rates were 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-N-34t.1).

35 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.).

36 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. BLK-1, at 2-30 n.36; HO-N-34t.1).

37 ANP stated that the proposed facility was assumed to operate without steam augmentation at 545 MW with an average availability of 92 percent (Exh. BLK-1, at 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 resulted in a conservative assessment of the economic need for baseload capacity relative to the attributes of the proposed project (id.).

("CT") units ("CT scenario") (Exh. HO-N-34t.5).[38] 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-N-34t.5).[39] ANP noted that its analysis assumes the same cost and performance characteristics for the generic CC capacity additions and the proposed facility (Exh. HO-N-34t.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. BLK-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 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-N-34n).

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

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38 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-N-34t.2).

39 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-N-34t.2).

dollars[40] over the five-year forecast period (Exh. HO-N-34t.5). The Company indicated that the annual cost savings would be \$2.6 million in 2000, \$4.2 million in 2001, \$6.1 million in 2002, \$4.4 million in 2003, and \$4.0 million in 2004 (id.).[41]

(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. BLK-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; Exh. EFSB-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 (Exh. EFSB-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. BLK-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.; Exh. HO-N-34t). Consistent with the existing NEPOOL dispatch analysis, the Company estimated total payment for energy based on two different scenarios of generic capacity

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

41 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-N-34t.5).

additions to meet the projected regional capacity requirements -- the CT scenario, and the CC scenario (Exh. HO-N-34t).[42]

The Company indicated that savings would be greater under the deregulated generation market dispatch than under the NEPOOL dispatch (Exh. HO-N-34t.5, HO-N-34-t.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-N-34t.5B).[43] 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.).[44]

(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 Board

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42 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. BLK-1, at 2-38; HO-N-34t).

43 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 (Exh. EFSB-1, at 123). He added that with successive additional entrants to the market, the incremental savings would decrease (id. at 121-122).

44 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-N-34t.5B).

standard indicates that need may be established on either reliability, economic, or environmental grounds. ANP Bellingham Decision, EFSB 97-1, at 37; Millennium Power Decision, EFSB 96-4 at 39-40; 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. ANP Bellingham Decision, EFSB 97-1, at 32-36; Millennium Power Decision, EFSB-96-4 at 36-39; 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. ANP Bellingham Decision, EFSB 97-1, at 38; Millennium Power Decision, EFSB 96-4, at 40; 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 the 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-N-34p; HO-N-34t).[45]

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

[45] The Company indicated that this approach was consistent with the method used to determine Massachusetts need for reliability purposes (Exh. BLK-1, at 2-32).

the five year forecast period (Exh. HO-N-34t.5). The Company indicated that the annual cost savings for Massachusetts would be $1.0 million in 2000, $2.0 million in 2001, $3.0 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-N-34-t.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. Here, the Company has provided analyses indicating that operation of the proposed facility would provide economic efficiency savings to Massachusetts ranging from $8 million under the existing NEPOOL dispatch scenario to $272 million under a deregulated generation market dispatch scenario, 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. BLK-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 CO_2 under two scenarios -- the ANP-in case and the ANP-out case (id. at 2-41 to 2-42; Exhs. HO-N-34t.9; HO-N-34t.10). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exhs. HO-N-34t.9; HO-N-34t.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. BLK-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. BLK-1, at 2-42 to 2-43; HO-N-34q; HO-N-34t.1). 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).[46] However, as noted above, the Company incorporated SO_2 allowance costs into the analysis (Exh. HO-N-34t.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-N-34t.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-

[46] 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).

year period from 2000 through 2004 (Exh. HO-N-34t.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 (3) 7.0 million tons of CO_2, or 3.2 percent of regional emissions (id.).[47]

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(S)). 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 (id.). 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. ANP Bellingham Decision, EFSB 97-1, at 41; Millennium Power Decision, EFSB 96-4, at 46; Altresco Lynn Decision, 2 DOMSB at 99. See also, Enron Decision, 23 DOMSC at 71; MASSPOWER Decision, 20 DOMSC at 388.

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47 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-N-34t.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.).

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. 1994 Cabot Decision, 2 DOMSC at 329; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 325-335. However, the Siting Board identified shortcomings with those applicants' dispatch analyses for addressing the potential for long-term air quality benefits including: (1) the assumption that displaced generation would be increasingly dispatched over time with continued load growth; (2) the assumption of constant emission rates over time, in pounds per million Btu ("lbs/MMBtu"), for generating units in the analysis; and (3) the failure to address the potential for significant amounts of retirement of existing generating units. 1994 Cabot Decision, 2 DOMSC at 328; Altresco Lynn Decision, 2 DOMSB at 100; EEC (remand) Decision, 1 DOMSB at 332-333. In more recent reviews of a gas-fired combined-cycle ("GCC") facility, the Siting Board raised concerns regarding assumed characteristics of future generic GCC units in the dispatch analysis, including assumed efficiency and size relative to the proposed project.[48] 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; 1994 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

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48 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 Power Decision, EFSB 96-4, at n.55; Berkshire Power Decision, 4 DOMSB at 302.

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.

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.[49]

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[49] 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

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.[50]

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;

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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.

50 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 ANP Bellingham Decision, EFSB 97-1, at 43 n.51; Millennium Power Decision, EFSB 96-4, at 49; Berkshire Power Decision, 4 DOMSB at 302.

the ANP-in case and the ANP-out case (Exhs. HO-N-34s; HO-N-34t.12; HO-N-34t.13). The analyses were based on meeting projected regional capacity requirements under both a CT scenario and CC scenario (Exh. HO-N-34t.12; HO-N-34t.13).[51]

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-N-34t.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 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.).[52]

(2) Analysis

The Siting Board recognizes the complexity included 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.

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51 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. BLK-1, at 2-43).

52 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-N-34t.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.).

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 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 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. ANP Bellingham Energy Decision, EFSB 97-1, at 46 to 47; Millennium Power Decision, EFSB 96-4, at 51 to 52; 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 Blackstone, Massachusetts, which would commence commercial operation in the second quarter of the year 2000 (Exh. BLK-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 (Exh. HO-A-11.1, at 3-24).

The Company stated that it used a three-phase screening process to examine all reasonable alternative technologies (id. 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, 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-4).[53] 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-4.1).

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

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[53] 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-3). 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 is on the order of $75,000 to $100,000 for each membership (Exh. EFSB-2, at 52 to 54).

information on the AFB, PFB, CG, PC and wind energy alternatives (Exh. HO-A-4.1). 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.). 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. EFSB-9; EFSB-9.1; EFSB-10.1(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. EFSB-24; EFSB-8; EFSB-8.1; EFSB-9; EFSB-9.1).

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 feasibility; reliability; cost-effectiveness; and ability to meet the identified need at a single site (Exh. BLK-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 reasonable 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.[54] 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.

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.

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[54] 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).

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. BLK-1, at 1-1 to 1-2, 3-2).[55]

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 (Exh. HO-A-11.1, 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 (id.; 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 (Exhs. BLK-1, at 3-12; EFSB-2, at 93 to 95).[56]

a. Air Quality

The Company asserted that the proposed project would be preferable to the four alternative technologies with respect to air quality (Exh. HO-A-11.1, at 3-15). In support of its assertion, the Company provided an analysis of the average annual emission rates and the

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[55] The Company stated that certain environmental 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 (Exhs. BLK-1, at 3-2; HO-A-11.1, at 3-15, 3-16).

[56] The Company stated that it used the DOE 1997 Annual Energy Outlook as the source document for developing fuel prices (Exh. EFSB-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).

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). The Company stated that emissions rates for the proposed project 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 evaluated alternatives would produce significantly higher annual emissions of the criteria pollutants SO_2, NOx, CO and CO_2 than would the proposed project, and slightly higher annual emissions of PM-10 and VOCs (id. at 3-15, 3-24; BLK 14.2; Exhs. HO-A-11.1, at 3-24; BLK 14.2). See Table 3, below.

Table 3

Alternative Technologies - Pollutant Emissions

	ANP-Blackstone*	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	0.018	0.056	0.10
VOC	0.003	0.005	0.004	0.007	0.004
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	49	106	69	116	70
CO_2 (1,000 tpy)	1,648	4,312	3,525	3,376	3,989

Source: Exhs. HO-A-11.1, at 3-24; BLK 14.2.

* Emissions for ANP-Blackstone, with the exception of VOCs, are initial estimates.

The record demonstrates that the annual air emissions and emissions rates 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. BLK-1, at 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 (id.). 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. EFSB-70, 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 (Exh. EFSB-71, at 52).[57]

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. HO-A-11.1, at 3-15 to 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 290,000 gpd based on use of a 545 MW turbine; the PFB alternative, with a 436 MW turbine, would require 230,000 gpd; the CG alternative would use a 202 MW turbine and require 700,000 gpd; and the PC alternative, with a 545 MW turbine,

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[57] The Company indicated that it was unlikely to exceed this maximum because the additional expense of purchasing more municipal water at higher rates would be financially disadvantageous to the proposed project (Exh. EFSB-70, at 71 to 72) (see Section III.B.2.b, below).

would require 290,000 gpd (id. at 3-16, 3-25).

The Company indicated that, with the exception of occasional periods of special maintenance activity, the process wastewater discharges for the proposed project would range from 3,400 to 27,000 gpd (Exh. HO-A-11.1, at 3-16). The Company stated that steam augmentation would not increase these volumes (Exh. EFSB-71, at 138 to 140). 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. HO-A-11.1, at 3-16, 3-25). The Company indicated that the process wastewater for the AFB, PFB and CG alternatives would be 250,000 gpd, 200,000 gpd and 350,000 gpd, respectively (id. at 3-25).

The record demonstrates that the water supply requirements of the proposed project would be approximately 62 percent of the water supply requirements of the AFB and PC alternatives, 78 percent of the water supply requirement of the PFB alternative, and 26 percent of the water supply requirement of the CG alternative. 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 11 percent of the wastewater generated by the AFB alternative, 14 percent of the wastewater generated by the PFB alternative, and eight percent of the wastewater generated by the CG alternative, but would be greater than the wastewater generated by the PC alternative by as much as 27,000 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. HO-A-11.1, at 3-16 to 3-17).

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. HO-A-11.1, 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.).[58] 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. at 3-17 to 3-18).

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.

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[58] 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 (Exhs. EFSB-11; EFSB-2, at 101). The Company knew of no existing studies documenting this view, however (Exh. EFSB-11).

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. HO-A-11.1, at 3-19). 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. at 3-18 to 3-19). The Company indicated that the project's tallest structures would be the two 180-foot stacks and two 110-foot air cooled condensers (Exh. BLK-1, at Figure 1.3-1). The Company indicated that construction of the proposed project would permanently alter 25 acres of the project site, which is a 140-acre open area, zoned "Residential 3",[59] within the northern portion of an approximately 400-acre active sand and gravel mining operation (id. at 1-10 to 1-11, 6-62). Portions of the site to the west and north of the footprint location are forested (id. at 1-10 to 1-11). The Mill River, running from north to south, forms a portion of the western site boundary (id.). The site is otherwise surrounded by primarily residential land uses (id.).

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 (Exh. HO-A-11.1, 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 25 acres within the proposed 140-acre site. The record further demonstrates that the scale and number of

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59 The proposed project is allowed under this category of zoning, but Special Permit review is required to ensure that the Town's design standards are met.

60 Additional structures associated with the coal-fired alternatives are for coal unloading and handling (Exh. HO-A-11.1, at 3-18).

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.

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. HO-A-11.1, 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 approximately 156,000 tpy for the CG alternative, 344,000 tpy for the PC alternative, 362,000 tpy for the PFB alternative and 367,000 tpy for the AFB alternative (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. ANP Bellingham Energy Decision, EFSB 97-1, at 59; Millennium Power Decision, EFSB 96-4, at 65; 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 54). 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. HO-A-11.1, at 3-11 to 3-12; EFSB-20.1; EFSB-20.2).[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 (Exhs. HO-A-11.1, at 3-11 to 3-12; EFSB-20; EFSB-20.1; EFSB-20.2).

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. HO-A-11.1, at 3-12; EFSB-8; EFSB-10; HO-RR-10.1; EFSB-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. EFSB-9).

With respect to fuel prices, the Company indicated that fuel price assumptions were based on the 1997 Energy Outlook (Exhs. HO-A-11.1, at 3-12; EFSB-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 (Exh. EFSB-2, at 95 to 99). The

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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. HO-A-11.1, at 3-22).

Company indicated that it assumed that the proposed project and each alternative would run constantly, limited only by its individual equivalent availability factor (Exh. HO-A-11.1, 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 (Exhs. HO-A-11.1, at 3-11 to 3-12; EFSB-20; EFSB-20.1; EFSB-20.2).

Table 4

TECHNOLOGY PARAMETERS AND LEVELIZED COSTS

	ANP Blackstone	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.
4. 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. EFSB-20.1-C (conf.); EFSB-20.2-C (conf.)).

Sources: Exhs. HO-A-11.1, at 3-21, 3-23; EFSB-20.1; EFSB-20.2.

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, 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. HO-A-11.1, 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 3-20). 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 (Exh. EFSB-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. 1998 Cabot Power Decision, EFSB 91-101A at 31; ANP Bellingham Power Decision, EFSB 97-1, at 66; 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. 1998 Cabot Power Decision, EFSB 91-101A at 31; ANP Bellingham Power Decision, EFSB 97-1, at 66; Berkshire Power Decision, 4 DOMSB at 345.[62]

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[62] 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 proposed project was filed pursuant to G.L. c. 164 § 69J, rather than § 69J¼, the Siting Board reviews the viability of the proposed project in this decision.

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 proposed project in the deregulated market in order to assess the financiability of a proposed merchant plant (Exh. BLK-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 Bellingham, Massachusetts and Gorham, Maine (Exh. HO-V-8). ANP stated that its parent American National Power, the United States development and operating affiliate of NP, would use cash flow from ongoing operations to fund development of the proposed project (Exh. BLK-1, at 4-2). ANP stated that 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 monies 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. BLK-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 NP has investments in and/or operates approximately 24,100 MW of generating capacity throughout the world and that American National Power

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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. BLK-1, at 4-2).

has an ownership share totalling 678 MW in 1,536 MW of generating capacity in the United States (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 both the Blackstone and Bellingham facilities (id.; Exh. EFSB-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 (Exh. EFSB-3, at 108).

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 (Exhs. V-12 (conf); EFSB-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 (Exh. EFSB-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 (id. 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. at 86-87).

The Company indicated that the proposed project and the Bellingham facility would be the first plants to be built by ANP exclusively as merchant plants and that the power from the proposed project would be marketed by ANP Blackstone Energy Company (id. at 64-65; Exh. BLK-1, at 1-1). 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 (Exh. EFSB-3, 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 demonstrated financial viability assuming pool prices (id. 111-112). ANP added that its economic efficiency analysis also demonstrated the proposed project's competitiveness in the deregulated market (Exh. BLK-1, at 4-1).

The Siting Board recognizes that the proposed project, like other generating projects reviewed by the Siting Board in recent years, 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. 1998 Cabot Power Decision, EFSB 91-101A at 35; ANP Bellingham Decision, EFSB 97-1, at 69; 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 during the past ten years (Exh. BLK-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 engineering, procurement, and construction ("EPC") contracts where the contractor was also the equipment vendor (id.).

The Company indicated that it is currently negotiating an EPC contract with ABB (id. at 4-5; Exhs. V-14(Rev.); V-41; V-41-1(conf.)). 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 (Exh. BKL-1, at 1-5). ANP stated that ABB will design and construct the plant to achieve a 20.5 month construction schedule (id. at 4-5; Exh. HO-V-15). In addition, ANP stated that ABB has agreed to a guaranteed heat rate, output, and schedule terms with liquidated damages on a "keep-whole" basis so that the viability of the proposed project would not be jeopardized if any of the guarantees were not met (Exhs. BLK-1, at 4-5; EFSB-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 (Exh. EFSB-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 the 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; Exh. HO-RR-8.1). The Company noted that a minimum availability of 92 percent is projected for the life of the proposed project (Exh. EFSB-3, 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). 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 use of a newer technology, aggressive guarantees from ABB with respect to heat rate, output and availability will mitigate those risks for 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-16). In addition to the Bellingham and Blackstone units, ANP stated that it is currently developing two merchant

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

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 two new 1.1 mile long 345 kV transmission lines in the towns of Blackstone and Mendon, and a new 345 kV substation located within the site of the proposed project (Exh. BLK-16, at 1-3; Tr.-J-1, at 77). The Company indicated that the transmission line would be located in a new 300-foot wide utility right-of way ROW (id. at 1-6). The interconnection, which is jurisdictional to the Siting Board, has been docketed as EFSB 98-2.[65] ANP provided a system impact study which details the impacts to the BECo and New England Power Company ("NEPCo") transmission systems of interconnecting both the proposed facility and the proposed ANP Bellingham facility to the transmission grid, and which identifies system-wide upgrades that will be required for interconnection (Exh. HO-V-27.4). The Company indicated that it anticipated that it would not issue a notice to proceed with the proposed project until the transmission line was fully permitted (Tr. 4, at 25).

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. 1998 Cabot Power Decision, EFSB 91-101A at 38; ANP Bellingham Decision, EFSB 97-1, at 72; 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 generating 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. We also note that the Company has stressed its intentions to provide low cost, clean power and has stated

65 The system-wide upgrades are further discussed in Section III.B.2.g, below.

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 BECo 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 ANP Bellingham Decision, EFSB 97-1, at 72; Millennium Power Decision, EFSB 96-4, at 82-83; Berkshire Power Decision, 4 DOMSB at 336.[66] 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 BECo.

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 V, below). Should the ABB GT24/26 turbine be unable to perform substantially

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[66] In the 1998 Cabot Power Decision, the Siting Board found that since only minimal upgrades would be necessary to interconnect the project, thereby alleviating interconnection issues relating to difficulty and cost, the proponent would not be required to demonstrate access to the regional transmission system through the submission of a signed interconnection agreement. EFSB 91-101A at 39. Here, the interconnection of the proposed project is more complex.

as expected, ANP would be required to notify the Siting Board as explained in Section V, 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 BECo 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 also has found that, upon compliance with the above conditions relative to a signed EPC contract and a signed agreement for access to the regional transmission system, 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. 1998 Cabot Power Decision, EFSB 91-101A at 40; ANP Bellingham Decision, EFSB 97-1, at 74; Altresco-Pittsfield Decision, 17 DOMSC at 381-382. In cases 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. 1998 Cabot Power Decision, EFSB 91-101A at 40; Millennium Power Decision, EFSB-96-4, at 85-86; Altresco-Pittsfield Decision, 17 DOMSC at 382-383. In cases where the proponent has demonstrated experience in the operation of generating facilities, an operations and maintenance ("O&M") contract has not been required. ANP Bellingham Decision, EFSB 97-1, at 75.

ANP stated that the proposed project would be competitively priced, new, efficient and clean (Exh. BLK-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 (Exh. EFSB-3, at 114-115). He further stated that ANP Operating Company currently operates the Milford Power facility in Milford, Massachusetts, 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. BLK-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) catastrophe 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 a recent case, the Siting Board noted that provision of an executed O&M contract was required only when the proponent has relatively little experience in the development and operation of a major energy facility. ANP Bellingham Decision, EFSB 97-1, at 75. 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 Siting Board's conclusions regarding the Company's O&M plans 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 V, 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 (Exh. EFSB-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. BLK-1, at 4-16). ANP stated that the proposed project is located in close proximity to an interconnection of Tennessee and Algonquin Gas Transmission Company ("Algonquin") pipelines in Mendon, a potential liquid point of receipt (Tr. 3, at 14, 27 to 29).[67] ANP indicated that it plans to connect to the Tennessee pipeline, via a 1.15-mile lateral to be constructed by Tennessee, and that Tennessee has initiated proceedings for construction of the connecting pipeline with the FERC (Exhs. BLK-1, at 1-13; HO-V-36; Tr. 3, at 14-15). ANP indicated that although it does not currently plan to physically interconnect the proposed project with Algonquin, it could potentially interconnect with both the Tennessee and Algonquin pipelines due to their location (Tr. 3, at 15; Company Brief at 83).

ANP explained that there is no significant differences between the proposed gas supply arrangements for the proposed Blackstone and Bellingham facilities (Tr. 3, at 52). The Company stated that it anticipates a firm gas supply for the proposed project (Exh. EFSB-3, 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 on the Tennessee or Algonquin 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; Tr. 3, at 17, 20-23, 26-27). The Company indicated that it issued a Request for Proposals ("RFP") for a 365-day gas supply for the proposed Blackstone facility and two additional generating facilities proposed by ANP in Bellingham, Massachusetts and Gorham, Maine (Exhs. EFSB-3, at 151-152, 157-158; HO-V-39). 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 (Tr. 3, at 61-62). The Company stated that the suppliers who responded to the RFP were equally reliable and that the responses therefore

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

would be evaluated on the basis of flexibility of the supply arrangements[68] and pricing[69] (Exh. EFSB-3, 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; Tr. 3, at 54). In addition ANP stated that it would consider an arrangement whereby the electricity buyer would provide gas for the project (Tr. 3, at 53).

The Company stated that it had initiated negotiations with potential suppliers and that it anticipated that a gas supply would be in place for the proposed facility prior to the commencement of construction (id. at 23). 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 (Exh. EFSB-3, at 167). The Company explained that the suppliers who responded were major participants in the industry who buy their gas from a number of sources (Tr. 3, at 24-25). In addition, the Company explained that factors such 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 23-24; Exh. EFSB-3, at 167-168).

The Company indicated that it is seeking firm transportation to be arranged by the supplier to the facility or by ANP back to a liquid point of receipt (Tr. 3, at 26-28). The Company stated that it has discussed transportation from liquid points of receipt with both Tennessee and Algonquin (Exh. EFSB-3, 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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68 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 (Exh. EFSB-3, at 153-154).

69 Mr. Kasle indicated that the pricing included in the responses was market-based and therefore in the range that had been anticipated (Exh. EFSB-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; Tr. 3, at 54). 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. BLK-7). 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. BLK-6).

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. 1998 Cabot Power Decision, EFSB 91-101A at 45; ANP Bellingham Decision, EFSB 97-1, at 78; 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. 1998 Cabot Power Decision, EFSB 91-101A at 45; ANP Bellingham Decision, EFSB 97-1, at 78; 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 the Siting Board's 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 that 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, has received offers well in excess of the requirements of the proposed facility, and has entered into negotiations for firm transportation arrangements with both Algonquin and Tennessee. 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 the Company's ability to take advantage of a variety of gas suppliers and transportation options. In addition, each of the three transportation options the Company has considered, 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 V, 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 the proposed 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 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 GENERATING FACILITY

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. ANP Bellingham, EFSB 97-1, at 81; Millennium Power Decision, EFSB 96-4 at 94; 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. ANP Bellingham, EFSB 97-1, at 81; Millennium Power Decision, EFSB 96-4 at 94; 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. ANP Bellingham, EFSB 97-1, at 81; Millennium Power Decision, EFSB 96-4 at 94; 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. ANP Bellingham, EFSB 97-1, at 81; Millennium Power Decision, EFSB 96-4 at 94-95; 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.[70] 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. ANP Bellingham, EFSB 97-1, at 82.

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. BLK-1, at 5-2; Tr. 1 at 12).

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

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70 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 Blackstone is not required as a matter of law or Siting Board regulation and is not necessary as a matter of policy.

spearheading of electric industry restructuring and the resulting favorable market environment for merchant plants (Exh. BLK-1, at 5-3).

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 to 5-3).

The Company stated that contacts to gauge receptivity with towns and with landowners proceeded in tandem with the site evaluation process (id. at 5-5). 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.). The Company testified that the proposed site was just outside the site selection corridor and was identified through an initial meeting with the town administrator of Blackstone (Tr. 1, at 20 to 21).

The Company established a series of threshold criteria by which it evaluated potential sites identified using the corridor approach described above (Exh. BLK-1, 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 5-4 to 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.) (see BLK 2.2.).

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. at 5-6 to 5-14).

To derive an overall suitability score, the Company developed weighting factors (on a 1-10 scale, with 10 indicating criteria of greatest importance) for each criterion based on the project team's judgment of the relative importance of each criterion in terms of overall site suitability (Exhs. BLK-1, at 5-5 to 5-17; HO-S-28). 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 (Exh. BLK-1, 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.). These were, in order of their scores, the Grafton 1 site, the proposed site (Blackstone 2), the Uxbridge 3 site, the Bellingham 1 site, the Mendon 1 site, and the Bellingham 4 site (Exhs. HO-S-1.1; HO-S-2). Ten sites received a score of 200 or greater (Exh. HO-S-1.1).

The additional four sites scoring above 200 were the Uxbridge 1 site, the Medway 2 site, the Holliston 1 site, and the Uxbridge 4 site (see Table 5, below) (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 (Exh. BLK-1, at 5-15). The Company stated that each of the next five highest-scoring 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).[71] 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.).

In addition to its site scoring matrix, the Company provided a qualitative comparison of the proposed site versus the other high-scoring evaluated sites (Exh. HO-S-30). The qualitative comparison examined advantages and disadvantages relative to the proposed site of sites with a score of 200 or greater (id.). Results are discussed below in descending order according to score:

(1) The *Grafton 1* site scored higher than the proposed Blackstone 2 site, in part because its land use history was deemed to represent less potential for site contamination (id.). It was rated superior with respect to wastewater discharge due to its proximity to a wastewater treatment plant (id.). In addition, it was further from residences than the Blackstone 2 site (id.).

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71 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. 1, at 20 to 24). The Company stated, however, that it had presented its proposed project at meetings open to the public and that members of the public had provided input to Company officials on those occasions (id. at 23 to 24). The Company indicated that in later stages of the site selection process, the Company held community informational meetings in Blackstone (id. at 22 to 24).

The primary disadvantages of the Grafton site with respect to the preferred site were its greater constraints on availability of water, relative proximity to protected species habitat, less compatible land use and zoning designation, and potential to impinge upon designated open space with the electrical interconnect associated with the project (id.). In addition, plans for development of a residential subdivision on the Grafton site had progressed to a stage that precluded Company control of the site for the proposed facilities (id.).

(2) The *Uxbridge 3* site, ultimately eliminated for a fatal flaw (zoning), scored lower than the proposed Blackstone site in the initial site screening and scoring (id.). It was found to have superior electric interconnection, with a transmission line abutting the site (id.). It was immediately proximate to a wastewater-treatment plant, which provided greater wastewater discharge opportunities (id.). It also had access to rail, which provided some construction advantages (id.). It carried fewer topographic constraints (id.). It was further removed from residences than the Blackstone 2 site (id.).

The disadvantages of the Uxbridge site with respect to the Blackstone 2 site were its less-favorable air-quality dispersion environment and the necessity to place the site footprint over a mapped aquifer (id.). More importantly, the Company decided that the Uxbridge site was fatally flawed due to lack of community acceptance as evidenced by the express prohibition of power plant construction and operation in Uxbridge by zoning bylaw (id.; Tr. 1, at 127).

(3) The *Bellingham 1* site scored lower than the Blackstone 2 preferred site (id.). In addition, at the time of the site selection process for the proposed facilities, the Bellingham 1 site was being pursued as a primary site in another EFSB proceeding (id.).

Historical land use at the Bellingham 1 site was considered to present less potential for site contamination than at the Blackstone 2 site (id.). The Bellingham 1 site was also closer to a wastewater treatment facility. Electric interconnection was better at the Bellingham 1 site, but this was offset by inferior gas interconnection (id.).

The disadvantages of the Bellingham 1 site included its greater proximity to protected species habitat, and the fact that the parcel had not been previously disturbed (id.). The Bellingham 1 site also required more clearing of land for the footprint of the project itself (id.).

(4) The *Mendon 1* site scored lower than the Blackstone 2 preferred site (id.). It was found to have superior electric interconnection, with a transmission line abutting the site (id.). Its historical land use indicated less potential for site contamination (id.). It was closer to a wastewater treatment facility and further removed from residences than the Blackstone 2 site (id.).

Disadvantages of the Mendon 1 site included a less-favorable air-quality dispersion environment, proximity to an airport, incompatible zoning, less compatible land use, and the location of wetlands such that placement of the proposed facilities on the footprint without wetlands encroachment would be difficult (id.).

(5) The *Bellingham 4* site scored lower than the Blackstone 2 preferred site (id.). Because a transmission line crossed the site, the Bellingham 4 site was considered superior to the Blackstone 2 site with respect to electric interconnection potential (id.). The Bellingham 4 site was also closer to a wastewater treatment facility and adjacent to a state highway (id.).

Disadvantages of the Bellingham 4 site included less favorable water supply potential, and less compatible zoning and land use (id.).

(6) The *Uxbridge 1* site, ultimately eliminated for a fatal flaw (zoning), scored lower than Blackstone 2, the preferred site, in initial screening and scoring (id.). Its advantages included the presence of electric transmission on site, less potential for site contamination, greater proximity to wastewater treatment and greater distance from residences (id.).

Zoning for the Uxbridge 1 site, however, was considered incompatible with its proposed use for two reasons: the Uxbridge zoning bylaws expressly prohibit power plants and the site itself is zoned agricultural (id.). The land use, town-owned open space, was also considered incompatible with use of the site for the proposed facilities (id.). In addition, road access to the site would require substantial upgrade (id.).

(7) The *Medway 2* site was advantageous relative to the proposed site, Blackstone 2, in several ways: the potential for site contamination was less, the topography involved fewer constraints, and site access was better (id.).

The Medway 2 site, however, would not be sufficiently large to allow placement of the proposed facilities without intrusion into areas of mapped endangered species habitat or estimated habitats for rare wetlands wildlife under the Massachusetts Natural Heritage and Endangered Species Program ("MNHESP") (id.). Zoning and land use at the Medway 2 site were also incompatible with use of the site for the proposed facilities (id.).

(8) The *Holliston 1* site had superior electric interconnection, fewer topographic constraints, and greater proximity to wastewater treatment than did Blackstone 2, the proposed site (id.).

From the standpoint of air quality, however, the dispersion environment at Holliston 1 would be inferior to that at Blackstone 2 (id.). In addition, a medium-yield aquifer underlies the Holliston 1 site, and both surface water bodies and mapped protected species habitat are within the site boundaries (id.). Finally, there is some question as to whether the proposed plant footprint could be located to avoid mapped wildlife habitat and the buffer zone surrounding the on-site surface water features (id.).

(9) The *Uxbridge 4* site, ultimately eliminated for a fatal flaw (zoning), scored lower than Blackstone 2, the preferred site, in initial screening and scoring (id.). The Uxbridge 4 site scored better than the preferred site with respect to electric interconnect, rail and road system access, and proximity to wastewater treatment facilities (id.).

The dispersion environment from an air quality standpoint would be less favorable than at the Blackstone 2 site (id.). The site is currently zoned residential, a classification incompatible with use of the site for the proposed project (id.). In addition, as with all evaluated locations in Uxbridge, the site is considered inferior to the Blackstone 2 site for the proposed facilities because of the express prohibition against power plants in the Uxbridge zoning bylaws (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.

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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.

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. ANP Bellingham, EFSB 97-1, at 87; Millennium Power Decision, EFSB 96-4, at 101; Cabot Decision, 2 DOMSB at 380-381.

The Siting Board is particularly interested in the consistent and appropriate application of site selection criteria in addition to their appropriate selection. For example, 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. 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.

With respect to electric interconnect impacts, the Company assigns its proposed site a medium rating, although the one-mile length of the currently proposed electric interconnect slightly exceeds the threshold which would seemingly qualify the site for a low rating on this criterion.

With respect to land use, the Siting Board notes that the Company's site selection process includes separate criteria for compatibility with existing land use and compatibility with zoning, and gives existing land use compatibility more weight than compatibility with zoning. Despite the potential for confusion in the application of the two criteria, they appear to have been applied consistently and appropriately in the instant proceeding.

Finally, with respect to community support, the Siting Board recognizes that 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. A persistent Siting Board concern, however, is 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 too late in the site selection process itself to make adjustments without great difficulty or cost. Here, the Company included a measure of "community support" based primarily on contact with local officials and historical public reaction to industrial development. However, the developer in the instant proceeding has also conducted public outreach earlier than developers in other generation facility cases recently before the Siting Board.

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.[73] Overall, the record indicates that the proposed 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 phase, quantitative (screening level) phase and final qualitative phase 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

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[73] We discuss at greater length the specific advantages and disadvantages of the site selected as a result of the screening process in the instant case in Sections III.B.2.a through III.B.h, below.

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. However, in cases such as this where there is no noticed alternative, the Siting Board still reviews geographic diversity relative to sites identified by the applicant.

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.

Table 5

ANP Blackstone																					
Company's Site Screening Evaluation Scoring																					
Southern Node, Sites w/ Weighted Scores ≥ 200																					
	Elec Intrc	Gas Intrc	Site Size	Site Topo	Site Contam	Water Avail	Waste-water	Road/ Rail	Dispers Env	Air-ports	Surf H_2O	Grnd H_2O	Fld-plain	En Spec Habitat	Land Use	Zoning/ Devel	Sens Recpt	Noise	Vis	Comm Supp	Raw Score	Wgt'd Score
Weighting Factor	10	10	6	5	10	6	5	4	10	3	7	8	10	8	7	5	10	4	5	10		
Site																						
Grafton 1	1	2	2	1	2	1	1	1	2	2	2	2	2	1	0	2	2	2	2	2	32	234
Blackstone 2	1	2	2	1	1	2	0	1	2	2	2	2	2	2	2	2	1	2	1	2	32	232
Uxbridge 3	2	2	2	2	1	2	2	2	1	2	2	1	2	2	2	0	2	2	2	0	33	228
Bellingham 1	2	1	2	2	2	2	1	1	2	2	2	1	1	1	1	2	1	2	1	2	31	219
Mendon 1	2	2	2	1	2	2	1	1	1	1	2	2	2	2	0	0	2	1	1	1	28	216
Bellingham 4	2	2	2	1	1	0	1	2	2	2	2	2	2	2	1	1	1	1	1	1	29	213
Uxbridge 1	2	2	2	1	2	1	1	0	2	2	2	2	2	2	0	0	2	2	0	0	27	208
Medway 2	1	2	2	2	2	1	1	2	2	2	2	2	2	1	1	0	1	1	0	1	28	206
Holliston 1	2	2	2	2	1	2	1	1	1	2	2	2	2	0	1	2	1	1	1	1	29	205
Uxbridge 4	2	2	2	1	1	2	2	2	1	2	2	2	2	2	1	0	1	2	0	0	29	204

B. Environmental Impacts of the Proposed Facility

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 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 they have considered a reasonable range of facility siting alternatives, and that the proposed site is superior to alternatives on the basis of balancing cost, environmental impact and reliability of supply. See ANP Bellingham Decision, EFSB 97-1, at 6; 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, 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.

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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 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).

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. BLK-1, at 6-2). In addition, the Company indicated that the proposed facility would fall under Title IV Sulfur Dioxide Allowances and Monitoring regulations beginning in the year 2000 (Exh. HO-EA-1.1, 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]

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75 The MDEP has adopted the NAAQS limits as MAAQS.

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-1.1, 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 (continued...)

(Exh. BLK-12.2, Vol. I, at 5-1, 8-22).

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. BLK-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. BLK-12.2 at 8-2; HO-EA-24.2, at 6.2-4, 6.2-16).

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. BLK-1 at 6-4; HO-EA-1.1 at 3-3; HO-EA-24.2 at 6.2-3). Thus, 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-24.2, at 6.2-4).

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 6.2-5).

(…continued)

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 (Exh. BLK-12.2, Vol.1, at 5-1, 8-22).

(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-24.2, at 6.2-16; HO-EA-1.1, at 4-13; HO-RR-40.2). 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. HO-EA-24.2 at 6.2-1, 6.2-19). 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 (Exhs. BLK-1 at 6-22; HO-EA-24.2 at 6.2-21).

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 (Exh. HO-EA-24.2, at 6.2-13 to 6.2-15). 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 (Exhs. HO-EA-1.1, at 4-1 to 4-13; HO-EA-24.2, at 6.2-13 to 6.2-15).

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. HO-EA-1.1, at 3-1, 4-2; HO-EA-24.2, at 6.2-4, 6.2-14). 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 75 percent load at an ambient temperature of 0 degrees Fahrenheit[78] (Exh. HO-EA-24.2, at 6.2-18).

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

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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 0 degrees Fahrenheit (Exh. HO-EA-24.2, at 6.2-18).

(Exhs. BLK-1, at 6-2, HO-EA-24.2, at 6.2-1; HO-RR-40.2). 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] (Exh. HO-EA-24.2, at 6.2-17).

With respect to emissions of non-criteria pollutants and air toxics, the Company stated that ISCST3 modelling was conducted to estimate emissions of formaldehyde, sulfuric acid, and ammonia. The Company then compared the predicted concentrations of these pollutants to the applicable MDEP standards[80] (Exhs. BLK-12.2, Vol. 1, at 8-33; HO-RR-40.2). The Company stated that the resulting concentrations were predicted to be below SILs for all three substances (id.).

The Company performed additional, more refined modelling -- using the EPA recommended ISCST3 model which incorporates hourly meteorological data -- to further evaluate the expected concentrations of non-criteria pollutants against the applicable Massachusetts TELs and AALs. The Company stated that its refined modelling comprised a 30 square kilometer receptor grid surrounding the facility site, and incorporated elevation data for all significant terrain features within that area (Exh. HO-EA-1.1, at 5-18 to 5-20). 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 concentrations of all non-criteria pollutants were predicted to

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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-24.2, at 6.2-18).

80 The applicable standards are MDEP Threshold Effects Exposure Limits ("TELs"), and annual average Allowable Ambient Limits ("AALs") (Exhs. HO-EA-1.1, at 5-12; BLK-12.2, Vol. 1, at 8-33).

be below the applicable TELs and AALs for the identified maximum impact load condition (Exhs. HO-EA-1.1 at 5-26; HO-RR-40.2).

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. HO-EA-24.2, at 6.2-24).

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 (Exhs. BLK-12.2, Vol.1, at 4-14, 8-28; HO-N-25; HO-EA-24.2, at 6.2-21). 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, the five-year reductions would be several times larger than the proposed facility's own emissions over the same period (Exhs. HO-EA-24.2, at 6.2-21; HO-N-25) (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. HO-EA-24.2, at 6.2-23, 6.2-24).

With respect to the analysis of cumulative impacts ordered by the Secretary of Environmental Affairs, the Company stated that it conducted interactive source modelling to prepare a cumulative air impacts analysis as part of its DEIR for the proposed project. The Company's analysis addressed both the ANP Bellingham and ANP Blackstone projects, and a generation project proposed for a site within the Town of Bellingham by IDC in docket EFSB 97-5.[81] Additionally, the analysis considered other major sources in the region that met the

[81] The Siting Board notes that the air emissions profile of the proposed IDC-Bellingham facility changed after completion of the interactive source model. In a filing with the Siting Board, the proposed nominal output of the IDC Bellingham project was reduced from 1035 MW to 700 MW. Therefore, the Siting Board notes that the results of the interactive source model presented in this case likely are conservative with respect to cumulative air impacts.

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. BLK-12.2, Vol.1, at 8-22). The Company stated that it identified, and included in its interactive modelling, three proposed and nine existing sources that met one of the two above criteria.[82]

The Company stated that it used the ISCST3 model with the same model inputs and meteorology as for its refined analysis for the proposed project alone (id. at 8-23). The Company indicated that results of the interactive source model demonstrated that the maximum combined concentrations of criteria pollutants from both the existing and proposed sources, plus existing background levels, would be within well MAAQS and NAAQS (id.; Exh. HO-RR-43). 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 Ocean State Power 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 (Exh. HO-RR-43).

(b) Analysis

The Company has demonstrated that emissions of criteria and other pollutants from the proposed facility at the proposed site would be consistent with a minimum impact on existing air

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[82] The Company stated that the criteria for selecting among existing sources were 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, Ocean State Power (two units), and Woonsocket Waste Water Treatment Facility (Exh. BLK-12.2, Vol. 1, at 8-22). 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 (id.).

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 well within the applicable MAAQS and NAAQS for all criteria pollutants. Moreover, the analysis demonstrates that emissions from the proposed facility would represent a small fraction of those standards.

(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-24.2, at 6.2-19). 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 the proposed use of dry low-NOx combusters and SCR for NOx control would achieve a NOx emission rate of 2.3 ppm (Exh. HO-EA-24 (Rev.)). The Company indicated that, based on expected facility NOx emissions of 151 tpy, the proposed facility would require offsets for 190.3 tons of NOx per year (id.). The Company stated that it had completed the acquisition of 190 tons of NOx offsets for the project, and identified the source of these offsets as Nantucket Electric Company (Exh. HO-RR-42)(Rev.).

The Company indicated that the proposed facility would emit a maximum of 1,948,504 tpy of CO_2 and asserted that the CO_2 impacts of the proposed facility would be minimized consistent with Siting Board requirements (Exhs. HO-EA-24.2, at 6.2-20 to 6.2-21; Tr. 8, at 7). In researching possible CO_2 mitigation strategies for the proposed facility, the Company stated that it had met with four organizations; (1) the Conservation Law Foundation, (2) the Charles River Watershed Association ("CRWA"), (3) the Blackstone River Watershed Association, and (4) the New England Forestry Foundation, all regarding projects that would result in effective CO_2 mitigation for the proposed facility (Exh. HO-EC-3). 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.; Tr. 8, at 7-16).

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. HO-EA-24.2, at 6.2-21). 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-EA-24.2, at 6.2-21; HO-N-25.2 (S)). 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 8,314,500 tons of CO_2 emissions over the same period (Exh. HO-N-25.2 (S)). (See Section II.A.4.a, above).

Finally, the Company considered the impact of its proposed on-site and off-site tree clearing on annual CO_2 assimilation. As discussed in Section IV. D. 3, below, construction of the proposed utility corridor that would contain both an overhead electric transmission line and an underground gas pipeline would result in the permanent clearing of approximately 25.6 acres of trees both on-site, and off-site in the towns of Blackstone and Mendon (Exh. HO-RR-J8). The Company explained that, as an offsetting consideration, its proposed post-construction on-site landscaping program would include tree planting on approximately 17 acres of the site that currently are unforested (id.; Exh. BLK-12.2, Vol. 1, at 7-5, 7-6, Fig. 7-13). The Company used data from the United States Department of Energy and the United States Forest Service to estimate a lost carbon sequestration rate of .95 metric tpy per acre[83] due to the proposed tree removal (Exh. HO-RR-38).

(b) Analysis

The Company has presented facility emissions 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 represents that it has obtained the number of NOx ERCs (190 tons) needed for the proposed project, 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 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.[84] In the Dighton Power Decision, the Siting Board expressed an expectation that the contributions of future project developers would reflect that set forth in that decision, 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 unadjusted contribution requirement would be $584,550. Therefore, the Siting Board requires the Company to provide CO_2 offsets

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83 The Company's estimate is based on coniferous forest and reflects tree mortality rates applicable to the northeast United States (Exh. HO-RR-38).

84 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.

through a total contribution of \$620,691[85] to be paid in five annual installments during the first five years of facility operation, to a cost-effective CO_2 offset program or programs to be selected upon consultation 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 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.[86]

With respect to the impact of tree clearing on CO_2, the record indicates that 25.6 acres of trees would be removed to allow for construction of the electric and gas interconnects for the proposed facility. In several recent cases, the Siting Board has recognized that the clearing of existing woodlands to allow for project development may have implications with respect to CO_2, specifically that tree clearing represents the loss of a natural resource that affects CO_2 levels in the atmosphere.

To characterize the impact of the proposed tree clearing in terms of its effect on CO_2, the Company provided an estimate of the carbon sequestration capacity of trees from data relative to coniferous forest lands in the northeast. Based on that data, the Company estimated that carbon sequestration capacity that would be lost due to tree clearing would be .95 metric tpy per acre.

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85 The contribution is based on offsetting one percent of facility CO_2 emissions, over 20 years, at \$1.50 per ton. The 20-year amount of \$584,550 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 \$116,910; year two \$120,417; year three \$124,030; year four \$127,751; year five \$131,583. See Cabot Power Decision, EFSB 91-101A; ANP-Bellingham Decision, EFSB-97-1, at 104; Millennium Power Decision, EFSB 96-4, at 114, 117-118.

86 The net present value amount is to be based on discounting, at ten percent, the five annual payments totalling \$620,691. See Cabot Power Decision, EFSB 91-101A, at 57; ANP Bellingham Decision, EFSB 97-1, at 104; Millennium Power Decision, EFSB 96-4, at 117-118. The single up-front payment of \$514,738 would be due by the end of the first year of operation.

The Siting Board is concerned that the record does not contain information sufficient to derive an accurate annual carbon sequestration rate for the actual woodlands that would be removed as a result of facility construction. Specifically, the record does not indicate that the affected woodlands are solely coniferous, nor does it provide an estimate of carbon sequestration capacity for a forest of mixed coniferous and deciduous species -- a factor likely to be significant in determining the actual 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.[87] Altresco Lynn Decision, 2 DOMSB at 219; Eastern Energy Corporation Decision on Compliance, 25 DOMSC at 350, n. 67. To ensure consistency between cases in establishing required offset levels, the Siting Board determined that it was appropriate to 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.

The Siting Board has recognized in past reviews that the application 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 mixed woodlands at the proposed site.

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[87] In Eastern Energy Corporation Decision on Compliance, the estimated cost CO_2 offsets through participation in MASS Releaf was $3.33 per ton. Eastern Energy Corporation Decision on Compliance 25 DOMSC at 350.

In a recent case, the Siting Board expressed similar concerns about the suitability of record information relating to carbon sequestration and applied its judgement to determine the appropriate sequestration offset amount. ANP-Bellingham Decision, EFSB 97-1, at 105. Therefore, the Siting Board will set an adjustment allowance for the proposed tree clearing based on its most recent precedent. For purposes of this review, the Siting Board applies an offset requirement of 30 tpy of CO_2 per acre, over a 30 year period, as a reasonable basis to estimate the carbon sequestration that would be lost as a result of permanent tree clearing associated with the electric and gas interconnects. Id. Thus the allowance for clearing 25.6 acres would be 23,040 tons of CO_2. At \$1.50 per ton, this yields an additional first year offset contribution of \$34,560 to the CO_2 offset program or programs designed to offset facility emissions.

The Company intends to plant up to 17 acres of trees on the site as part of its proposed post-construction landscaping plan. The Siting Board recognizes that on-site tree planting may be an effective means to offset sequestered CO_2 lost by the removal of forested areas during facility construction. Therefore, the Siting Board will review the Company's plans for on-site tree planting in the context of the Company's comprehensive CO_2 offset proposal that is to be submitted following the commencement of commercial operations.

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.

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 (Exhs. EFSB-70, at 63, 124 to 163; EFSB-71, at 50 to 54).[88] 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 (Exh. EFSB-71, 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. BLK-1, at 6-30).

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 (Exh. EFSB-70, at 129, 131).[89] The Company also indicated that steam augmentation would increase the average daily water requirement of the proposed facility (Exh. EFSB-71, at 50 to 54). The Company provided estimates for water requirements above baseload water supply for its three scenarios

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88 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 (Exhs. BLK-1, at 1-6 to 1-7, 3-2; EFSB-70, 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.

89 The Company used 14,000 gpd as an approximate estimate of baseload input for its proposed facility (Exh. EFSB-70, at 129). Baseload input for the proposed facility would actually be lower -- 13,400 gpd -- according to the Company's engineering estimates (id.).

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-21). 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-20; HO-EW-21).

The Company stated that its water supply would come primarily from Town of Blackstone municipal water supplies (Exh. BLK-1, at 6-31). The Company provided a copy of its Agreement for Water and Sewer Services ("Agreement") with the Town of Blackstone (Exh. HO-V-29.1). The Agreement states, in part, that the Company has the right to withdraw water from Blackstone's municipal water supply in quantities of 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.).[90]

The Company anticipated that its proposed facilities would connect to the municipal system at the intersection of the proposed site access road and Elm Street (Exhs. HO-EW-5, HO-

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90 The Company's Agreement also addresses the matter of ANP's payment for its withdrawals of water from the Blackstone municipal water system (Exh. HO-V-29.1). According to the Agreement, ANP will be a customer of Blackstone'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.). The Agreement also provides that ANP will be billed at a rate of 1.5 times the highest rate block for usage over the daily limits 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), below.

EW-5.1). The connection would be via an extension of an existing main or a new, dedicated line (Exh. HO-EW-5).

The Company stated that it would participate financially in the design, construction and operation of infrastructure improvements to the Blackstone public water and sewer system to support the operation of its proposed facilities (id.; Exh. HO-EW-5.1). The Company also agreed to fund upgrades of selected Blackstone town wells to increase well water production to accommodate the water supply needs of the Company and the Town of Blackstone (Exhs. HO-V-29.1; HO-EW-5.1).

The Company stated that the proposed facility would include raw and demineralized water tanks, which would be used for summer steam augmentation and for emergency fire flows (Exh. BLK-1, at 6-31). 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 (Exh. EFSB-70, at 66). The Company stated that the raw and demineralized water storage on site would yield enough water for 3.7 days of operation of the proposed facility in the summer with steam augmentation (id. at 67 to 68). The Company indicated that it would fill its water tanks from the Town of Blackstone's municipal sources pursuant to the Agreement (Exhs. HO-EW-4; HO-V-29.1).

The Company indicated that at present, three groundwater supply wells, wells #1, #4 and #5, provide the daily water supply for the Town of Blackstone and that a fourth groundwater supply well, well #2, is used during periods of higher demand (Exhs. BLK 12.2, at 13-4 to 13-5). The MDEP conditionally approved an additional well, well #6, in October, 1997 (Exh. HO-EW-1.1).[91] The Company indicated that all of the existing Blackstone supply wells, as well as

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[91] 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 (Exh. EFSB-74, at 45 to 46, 57 to 61).

proposed well #6, are in the vicinity of Harris Pond at the lower end of the Mill River subbasin of the Blackstone River (Exh. HO-EW-18(S)).[92]

The Company asserted that water resources, including groundwater, surface water, wetlands, stormwater and wastewater, would not be significantly affected by the proposed facility (Exhs. BLK-1, at 6-26; HO-EW-27, at 5).[93] In support, the Company provided data for both the Blackstone water supply system and the groundwater resources on which the water supply system draws (Exh. HO-EW-1.1; HO-EW-1S.2; HO-EW-19(S); HO-EW-37(S); HO-EW-49). The data provided by the Company for the Blackstone water supply system included permitted average daily withdrawal and actual average daily demand for the years 1992 through 1997, and registered plus permitted annual average daily volumes from January 26, 1990 through February 28, 2009 (Exhs. HO-EW-1.1; HO-EW-1S.2; BLK 12.4) (see Table 6, below).[94]

The Company stated that the MA WMA allows permit holders to pump up to 0.1 mgd more than the amount specified in their water withdrawal permits (Exh. HO-EW-1S.2). Based on its registered and permitted withdrawal amounts and the 0.1 mgd margin, the Blackstone

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92 In addition to the Mill River, other water courses including the Quick Stream, which drains from Lake Hiawatha, flow into Harris Pond. Harris Pond drains directly to the Blackstone River, approximately 4,250 feet (straight line measure) from the downstream end of the pond (Exh. HO-S-12.3).

93 The Company also stated that cumulative drawdown of the water table and potential use conflicts between private and public wells are unlikely because: (1) private wells are generally constructed in bedrock and therefore pump water from relatively separate geologic units; (2) private wells pump small amounts of water compared to public supply wells; and (3) private wells are not allowed within 400 feet of public supply wells and at that distance pumping either type of well is unlikely to affect the other (Exh. HO-EW-39(S)).

94 The Massachusetts Water Management Act ("MA WMA") sets allowed withdrawals for the supply wells. The amounts specified are the sum of a registered volume and a permitted volume. The registered amount is fixed (.44 mgd for all existing Blackstone supply wells) and is based on historical water use in a given municipality, while the permitted amount is in addition to the registered amount and increases incrementally over four five-year periods (Exhs. EFSB-33; HO-EW-1S.2). Water withdrawal permits under the MA WMA are issued by MDEP (Exhs. HO-EW-1(S); HO-EW-1S.1).

water system would be able to withdraw average daily volumes of up to 1.01 mgd from March 1999 to February 2004, and up to 1.05 mgd from March 2004 to February 2004 (see Table 7, below).

Table 6
Blackstone Water System Permitted Average Daily Withdrawal,
Actual Average Daily Demand and
Unused Permitted Average Daily Withdrawal

Year	(A) Permitted Average Daily Withdrawal (mgd)	(B) Actual Average Daily Demand (mgd)	Unused Permitted Capacity (A) - (B)
1992	0.75	0.47	0.28
1993	0.75	0.52	0.23
1994	0.86	0.52	0.34
1995	0.86	0.56	0.30
1996	0.86	0.82	0.04
1997	0.86	0.82	0.04

Sources: Permitted average daily withdrawal for all years from Exh. HO-EW-1.1.
Actual average daily demand for 1992-1995 from Exh. HO-EW-1S.2; for 1996, extrapolated from Exh. HO-EW-1.1 at D5; for 1997 from Exh. BLK 12.4, at 3-27.

Table 7

Water Management Act Water Withdrawal Permits

Registered Plus Permitted

Annual Average Daily Volumes

Period	Permitted Volume (mgd)	Registered Volume (mgd)	(A) Total Volume (mgd)	(B) Additional Allowance (mgd)	(A)+(B)
01/26/1990-02/28/1994	0.31	0.44	0.75	0.1	0.85
03/01/1994-02/28/1999	0.42	0.44	0.86	0.1	0.96
03/01/1999-02/28/2004	0.47	0.44	0.91	0.1	1.01
03/01/2004-02/28/2009	0.51	0.44	0.95	0.1	1.05

Sources: Permitted volumes for all periods from Exh. HO-EW-1S.2. Additional allowance for all periods from HO-EW-1(S).

The Company also indicated MDEP has set maximum pumping rates[95] for Blackstone's individual wells, including new well #6, as follows: well #1, 0.29 mgd; well #2, 0.17 mgd; well #4, 0.32 mgd; well #5, 0.48 mgd; and well #6, 0.40 mgd (Exh. HO-EW-1.1). Thus the three supply wells used for Blackstone's water supply during periods of normal demand together provide water at the rate of 1.09 mgd (id.). With the additional 0.40 mgd from well #6, Blackstone could potentially have access to total water volumes of 1.49 mgd from its water supply wells during periods of normal demand, and as much as 1.66 mgd during periods of higher demand (id.).

The Company examined estimated population and water demand projections for the Town of Blackstone through the year 2020 to evaluate the ability of Blackstone's municipal water

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95 The approved pumping rate is the rate of withdrawal which cannot be exceeded without advance written approval from MDEP.

supply to meet the combined future water supply needs of the Town and the proposed facilities (Exhs. HO-EW-49.1; HO-EW-49.2). The Company relied for its estimated population and water demand projections on a report of historic and projected water use for the Blackstone River Basin ("Blackstone River Basin Report") prepared by the Massachusetts Department of Environmental Management ("MA DEM") (Exhs. HO-EW-49.1; HO-EW-49.2; HO-EW-49.3).[96,97] The Blackstone River Basin Report anticipates average day demand for Blackstone of 0.96 mgd for the year 2010 and 1.06 mgd for the year 2020 based on projected population growth, i.e., without incorporating water demand for the proposed facilities (Exh. HO-EW-49.1, at 73). The average daily water demand on the Blackstone municipal water supply system, combined with the maximum average daily usage for the proposed facility of 0.15 mgd -- based on the Company's Agreement with the Town of Blackstone -- would be 1.11 mgd (0.96 mgd plus 0.15 mgd) in the year 2010 and 1.21 mgd (1.06 mgd plus 0.15 mgd) in the year 2020 (id.; Exhs. HO-EW-1S.2; HO-V-29.1).

In evaluating the impacts of water withdrawals for its proposed facilities on water resources, the Company submitted 7Q10 low flow data[98] and average daily summer (July through

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96 The Company compared the MA DEM projected population for Blackstone against 1987-1996 actual population data gathered for Blackstone by the Town Clerk's Office (Exhs. HO-RR-46; HO-RR-46.1). The actual population increase over the examined time period is generally parallel to the MA DEM population predictions (Exhs. HO-RR-46; HO-RR-46.1). The MA DEM water use predictions are based on the MA DEM projected population (Exhs. HO-RR-46; HO-RR-46.1).

97 The Company also reviewed historical water use for the Town of Blackstone from 1987 to 1996 for comparison against population growth over the same period (Exhs. HO-RR-46; HO-RR-46.1). The Company indicated that Blackstone experienced a water use decline but an overall population increase from 1989 to 1992, and that Blackstone's water use in 1996 was lower than in 1987 despite an 18 percent increase in the Town's population over this period (Exh. HO-RR-46). The Company stated that, although water use correlates with population in general, other factors that are difficult or impossible to predict -- such as weather -- can affect water use more than population (id.).

98 The 7Q10 flow is, by definition, the lowest daily flow in a river or stream averaged

(continued…)

September) flow data for the Woonsocket, Rhode Island gauging station ("Woonsocket") in the Blackstone River Basin (Exh. EFSB 38.1). The Company indicated that the 7Q10 at Woonsocket is 65.3 mgd, or approximately 30 percent of the average Woonsocket summer flow[99] of 212 mgd (Exh. HO-EW-19(S)). The Company stated that maximum water use of the proposed facilities would be less than one percent of the Blackstone River's 7Q10 low flow as measured at the Woonsocket gauging station (Exh. HO-EW-19).

With respect to cumulative impacts of new generation facilities on the Blackstone River Basin, the Company stated that all of the water supply for the ANP Blackstone facility and a portion of the water supply for the ANP Bellingham facility would come from subbasins of the Blackstone River. The Company explained that its Blackstone and Bellingham facilities would be supplied from the Mill River subbasin and the Peters Brook subbasin, respectively, and noted that the two subbasins are not hydraulically connected above their confluences with the Blackstone River (id.). The Company indicated that the combined withdrawals for ANP's Blackstone and Bellingham facilities would be 0.15 mgd during summertime periods of low flow, again less than one percent of the measurement of the Blackstone River's 7Q10 low flow at the Woonsocket gauging station (id.).

The Company also calculated the amount of groundwater available for withdrawal by Blackstone's wells based on the wells' drainage area[100] and surficial geology (Exh. HO-EW-27

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[98](…continued)
over 7 days that is expected to occur every 10 years (Exh. EFSB 38.1).

[99] The average daily summer flow is defined as the average of the flows during July, August and September for the period of record (1929-1996 for Woonsocket) (Exh. HO-EW-19(S)).

[100] The Company indicated that the drainage area includes the MA DEP delineated Zone II recharge areas for Blackstone's existing wells and proposed well #6, and upstream areas draining to the Zone II areas. The Blackstone River Basin Report sets the estimated drainage area for the supply wells equal to the drainage area of the Mill River subbasin above Harris Pond, 25.3 square miles (Exh. HO-EW-49.2). The Company stated that because Blackstone's supply wells are all below the bottom of the Mill River (continued…)

(S)). The Company estimated the groundwater available for withdrawal at 5.71 mgd, representing the 95 percent flow duration[101] for the drainage area for Blackstone's existing supply wells and proposed well #6 (id.).[102]

The Company also provided approximate rates of groundwater recharge to Blackstone's supply wells from three sources relevant to wells constructed in sand and gravel aquifers: (1) precipitation infiltrating the surface of the aquifer; (2) groundwater inflow from underlying till and bedrock; and (3) induced infiltration of surface water to the aquifer by pumping (Exh. HO-

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[100](...continued)
subbasin identified in the Blackstone River Basin Report, the drainage area for the supply wells is greater than that for the Mill River subbasin (Exh. HO-EW-27(S)). The Company estimated the drainage area for the supply wells to be approximately 6.4 square miles larger than the drainage area for the Mill River subbasin, or 31.7 square miles (id.).

[101] Ninety-five (95) percent flow duration is a measure of low flow during dry periods (Exh. HO-EW-27(S)). It is the flow equaled or exceeded on average 19 months out of 20 (Exh. HO-EW-49.2, at Table 1).

[102] Based on data from the Massachusetts Geographic Information Systems Office ("MassGIS"), the Company calculated that, of the total drainage area of approximately 31.7 square miles, approximately 30 percent is underlain by stratified drift (Exh. HO-EW-27). The Company assumed that for a basin underlain by 30 percent stratified drift, the 95 percent flow duration is approximately 0.18 million gallons per day per square mile ("mgd/mi^2")(id.). The Company therefore estimated the 95 percent flow duration for the drainage area for Blackstone's wells to be 0.18 mgd/mi^2 times 31.7 mi^2, or 5.71 mgd (id.). The Company's measure of low flow is based on a USGS method which assumes a 95 percent duration for the overall period of record, rather than a drought period (Exh. HO-EW-27(S)).

The Blackstone River Basin Report, which reflects MA DEM's more conservative calculation of 95 percent flow duration, assumes low flow for a long-term drought condition, specifically, the 1980-81 drought period (id.; Exh. HO-EW-49.2). MA DEM's estimate of 95 percent flow duration is .05 mgd/mi^2, significantly lower than the USGS estimate (Exh. HO-EW-49.2). If MA DEM's estimate of 95 percent flow duration is used, the estimated 95 percent flow duration for the drainage area for Blackstone's supply wells becomes .05 mgd/mi^2 times 31.7 mi^2, or 1.60 mgd (id.; Exh. HO-EW-27(S)).

EW-37). The Company calculated recharge from precipitation at 0.94 mgd and recharge from till and bedrock at 1.03 mgd, for a total of 1.97 mgd (id.).[103] The Company did not calculate recharge from induced infiltration, but stated that its addition would further increase total recharge to the Zone II area (id.).

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. EFSB-39). According to CRWA estimates, 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 (id.). 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), stormwater remediation program for recharge infiltration (12 mgy recharge to groundwater), and septic system repair (6.26 mgy recharge to groundwater) (id.; Exhs. EFSB-56; EFSB-57).

The Company acknowledged 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 over baseload use (Tr. 71, at 112, 116 to 117).[104] 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

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103 The Company based its calculation on the total area (0.94 mi^2) of Zone IIs (state delineated recharge areas) for the supply wells and the USGS estimate of precipitation recharge rate per square mile of aquifer area (1.0 mgd): 0.94 mi^2 times 1.0 mgd/mi^2 = 0.94 mgd (Exh. HO-EW-37). The Company estimated the recharge to sand and gravel aquifers from till and bedrock for Blackstone's supply wells using the USGS estimate of 0.021 mgd per 1,000 feet of aquifer perimeter(id.). For the approximately 49,000-foot total perimeter of the Zone IIs for Blackstone's supply wells, the Company calculated recharge from till and bedrock at 49,000 feet times 0.021 mgd/1000 feet, or 1.03 mgd (id.).

104 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).

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 (Exhs. EFSB-55; EFSB-71, at 122 to 123).[105,106] The Company stated that the increase in design and capital costs of construction associated with steam augmentation capability would be negligible, and that no incremental fixed costs would be associated with steam augmentation (Exh. HO-EW-21). 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 direct wetland alteration would be required for the facility footprint or site access (Exh. BLK-12.2, at 11-4). However, the Company indicated that some disturbance of wetland buffer zone would be associated with construction of stormwater management features and the electric switchyard for the proposed facilities (HO-RR-50.1 at A-

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105 The Company explained that the heat rate for the proposed GT-24/26 unit would be 24 percent higher (less efficient) during steam augmented operation than it would during baseload operation (Exh. EFSB-55). 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.).

106 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. EFSB-48, 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.).

15). The Company anticipated that total impact to wetland buffer zone from construction of stormwater management features would be approximately 5,600 square feet (id.). The Company estimated that the electric switchyard, located on the eastern side of the footprint for the proposed facilities, would require grading in approximately 10,800 square feet of 100-foot wetland buffer zone to bring it to an elevation of 225 feet (id.). In addition, the fence surrounding the electric switchyard would lie partially in the 100-foot buffer zone of two woodlands (id.). The Company emphasized that work in the buffer zone would be minimized to the extent possible and would be accompanied by appropriate erosion and sedimentation controls, including the use of hay bales and silt fencing (id. at A-16).

The Company indicated that installation of underground utilities, including the wastewater interconnect, would occur in the resource areas "Bordering Land Subject to Flooding" and "Riverfront Area" within the existing paved gravel operation access road and at the Mill River Bridge (id. at A-2). The Company stated, however, that disturbance to sensitive resource areas would be avoided by attaching utilities to the existing Mill River Bridge and otherwise installing them along the new facility access road and existing access road (id.).

The Company also presented information regarding the wetlands impacts of the associated gas pipeline and electric transmission connection for the proposed facilities (Exhs. BLK-12.2, at 11-27 to 11-35; BLK-12.4, at 3-14 to 3-23). The Company indicated the gas interconnect would traverse buffer zone and would temporarily impact an intermittent stream and its associated bordering vegetated wetlands (Exh. HO-J-E-3.1). The Company stated that it would use standard measures to minimize impacts to wetlands and buffer zone including the use of haybales and silt fencing along the wetland boundary and reseeding to restore any temporarily disturbed vegetated areas (Exh. BLK-12.2, at 11-28). The Company also anticipated that installation of the electric interconnect would include construction within the buffer zone of an on-site BVW (wetland #1) (id.). The Company indicated that no construction would occur within wetlands or buffer zone along the off-site portion of the electric interconnect route (see Section IV.D.3.1, below).

The Company indicated that the use of air cooled condensers and internal water recycling would result in low wastewater flows (Exh. BLK-12.2, at 13-6). The Company stated that process discharge volumes would range from approximately 3,400 gpd during normal baseload operations to 5,000 - 7,000 gpd when the proposed facility operates with frequent stops and starts (id.). The Company stated that the use of steam augmentation would not affect wastewater discharge volumes (Exh. EFSB-71, 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 (id. at 135 to 136; Exh. BLK-12.2, at 13-6). The Company indicated that discharge from major maintenance inspections would occur over periods of up to several days (Exh. EFSB-46).

The Company indicated that under its Agreement with the Town of Blackstone, process wastewater from the proposed facilities would be discharged to the Town's municipal sewerage system, which discharges to the Woonsocket (Rhode Island) Wastewater Treatment Facility ("WWTF") (Exh. BLK-1, at 6-33). The Agreement specifies that the Company shall have the right to discharge an annual daily average of 10,000 gpd of wastewater into the Town's public sewer system (Exh. HO-V-29.1, at 4).[107]

The Company documented the availability of sufficient capacity at the WWTF for the wastewater flows from the proposed facilities (Exhs. BLK-12.2, at 13-6; HO-EW-6). The peak daily capacity of the WWTF is 16.0 mgd; typical flows are approximately one half that amount (Exh. BLK-12.2, at 13-6). Blackstone has a contracted allocation with the WWTF of 0.75 mgd, but presently uses 0.174 mgd (Exh. HO-EW-6). Based on information provided by the Company, new house connections resulting from sewer expansion associated with the proposed facilities, in addition to the sewer connection for the proposed facilities themselves, would increase Blackstone's total wastewater discharge to the WWTF by approximately 0.085 mgd to 0.26 mgd, still well within Blackstone's contracted allocation (id.).

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[107] The Company may discharge more than 10,000 gpd into Blackstone's public sewer system if the Town agrees to provide additional sewer capacity to the Plant (Exh. HO-V-29.1, at 4).

ANP estimated that an additional 2,640 gpd of sanitary wastewater would be generated by the proposed facilities (Exh. BLK-12.4, at 3-30). The Company's plans incorporate an on-site septic system to dispose of these additional wastewater flows (id.). The Company indicated, however, that use of an on-site septic system would require a waiver from 310 CMR 15.004(4) (id.). The Company anticipated applying for the referenced waiver from the Blackstone Board of Health (id.).[108] The Company asserted that the on-site septic system would recharge underlying groundwater resources of the Blackstone River basin and its use would therefore be consistent with the water conservation plan for Blackstone and Bellingham developed with the CRWA (id. at 3-30 to 3-31).

The Company indicated that it developed a stormwater management plan for the proposed facility designed to (1) minimize pollutants in the proposed facility's stormwater discharges; (2) assure compliance with the terms and conditions of the National Pollutant Discharge Elimination System ("NPDES") Multi-Sector General Permit requirements; (3) attenuate peak stormwater runoff discharge rates to values not greater than the predevelopment rates; and (4) meet the Massachusetts Stormwater Management Performance Standards as well as the specifications of the Blackstone Town Code of By-Laws, Chapter 119 (Exh. BLK-12.2, at 11-2, 12-4 to 12-14, Appendix G).[109] The Company also provided a copy of

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108 The Company explained that 310 CMR 15.004(4) prohibits the use of a septic system when sufficient municipal capacity exists (Exh. BLK-12.4, at 3-30). To qualify for a waiver, the proponent must disclose the volume of wastewater that will be discharged to the system, and demonstrate that the site conditions satisfy the requisite percolation and leaching characteristics as defined by local and MA DEP regulations (id.). The Company stated that it anticipates providing the necessary calculations of sanitary volumes as well as information necessary to demonstrate the percolation and leaching characteristics of the site at the time of the application for a waiver from the local Board of Health (id.).

109 The Company stated that two stormwater features (temporary and permanent swales) would be located within the buffer zones of two wetlands, but were expected to improve water quality discharges to all downgradient wetland areas (Exh. HO-RR-50.1).

its Notice of Intent to the Blackstone Conservation Commission containing details of its stormwater management plan (id. at 11-2; Exh. HO-RR-50.1(2)).

With respect to state-listed rare species or species with special habitat needs, the Blackstone River Basin Report identified the Mill River 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 Blackstone withdrawals (Exh. HO-EW-49.2). The Massachusetts National Heritage and Endangered Species Program ("NHESP") has identified Quick Stream as estimated habitat for the American Brook Lamprey, but does not recommend associated special constraints on water withdrawals by the Town of Blackstone or other nearby municipalities (Exh. HO-RR-50.1, at Att. C).

(2) 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, which is substantially less (by a factor of more than two) than the water supply needs of the most water-efficient plant approved by the Siting Board other than ANP's twin Bellingham plant (see n.110, below). The Siting Board therefore finds that the water supply impacts of the proposed facility have been minimized during baseload operations.

ANP 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 with the exception of ANP's proposed plant in Bellingham.[110]

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, would have no adverse effect on baseload operating efficiency. The proposed peaking capability also would result in lower regional air emissions than alternatives,[111] 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 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 Blackstone's

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110 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.

111 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.

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 Blackstone and vicinity, we also consider issues related to the water consumption of the proposed Blackstone facility in the context of existing water use at the Milford Power and NEA facilities, and the proposed use by the Blackstone, Bellingham and IDC facilities.

The Company states that it has signed a contract which will limit water withdrawals for its proposed facility to levels well within the capacity of Blackstone'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 Blackstone's water system, and in quantities of up to 250,000 gpd during the period November 15 through March 15, to be similarly billed for a total of up to 55.75 mgy.[112] The Company's estimates of annual water use range from 29.2 mgy to 54.2 mgy, depending upon the frequency with which steam augmentation is used. The Siting Board 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, and no more than 20 percent, is therefore realistic.

The record demonstrates that the permitted capacity of the Blackstone municipal water system can accommodate withdrawals for the proposed facility at the rate of 54.2 mgy (.15 mgd) in addition to all other present Town withdrawals. However, the record also demonstrates that the combined water supply requirements of the Town and the proposed facility will increase more quickly than permitted volumes for the Town of Blackstone under its MA WMA water withdrawal permit.

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112 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 1.5 times the highest rate block for all usage over the daily averages noted above.

Based on current projections, the Town of Blackstone will almost certainly need to request an increase in its MA WMA water withdrawal permit from MA DEP on or before the permit period ending February 28, 2004. Thus, the MA WMA permit limits indicate a potential constraint on the ability of local water resources to accommodate the facility's water requirements in the long run. However, other analyses in the record, further addressing issues of water availability, impacts on watersheds and mitigation, are also relevant to the Siting Board's review of the acceptability of the proposed facility's water usage.

With respect to water availability, the permitted pumping capacity of Blackstone's individual supply wells under the MA WMA will be greater than projected water requirements of the Town of Blackstone for all uses, including the proposed new power plant. In addition, the record demonstrates that, based on 1992-1997 data, precipitation recharge for Town of Blackstone wells is above the combined levels of average annual aquifer withdrawals plus future annual withdrawals for the proposed facility. The record also demonstrates that there are no conflicts between the proposed facility's demand on the public well system in Blackstone and the use of private wells, because the aquifers drawn upon are likely to be different.

With respect to watershed impacts, water for the proposed facility would be withdrawn from Town of Blackstone wells in the watershed of the Blackstone River. The record indicates that the ANP Blackstone facility's water use, considered alone and considered in cumulative terms with that of the Bellingham facility, would represent less than one percent of the flow in the Blackstone River during 7Q10 low flow conditions.[113] On a subbasin level, Town of Blackstone supply wells draw water from the vicinity of Harris Pond at the downstream end of the Mill River subbasin -- thus watershed impacts on upstream resources are avoided. The record further shows that, based on the Company's analysis determining minimum basin flow likely to be available in 95 percent of all months, a 5.71 mgd supply is available for the Mill

113 Other existing and proposed water withdrawals to supply nearby generating facilities, including the Milford Power, NEA and proposed IDC facilities, are located in the Charles River Basin. NEA Decision, 16 DOMSC at 393-396, 404; Enron Decision, 23 DOMSC 137-180; Infrastructure Development Corporation, EOEA #11223, FEIR at 4.2-1 (December 15, 1998).

River subbasin and the additional drainage area of the Blackstone supply wells near Harris Pond -- an amount three to four times the projected long term water demand for the Blackstone system. Thus, a portion of minimum basin flow is likely to remain available to help maintain the environmental characteristics of Harris Pond and its outflow to the Blackstone River. Moreover, as part of its review of new wells such as Blackstone's proposed well #6, MA DEP may require pump tests or other analyses to ensure increased pumpage will not adversely affect water levels.

With respect to mitigation, the Company intends to fund a CRWA-developed water conservation program for Blackstone and Bellingham, 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 Blackstone and ANP Bellingham 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. In addition, the 6 mgy savings from septic repairs could be more than offset by new house connections resulting from a project-related sewer expansion. 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.[114]

On balance, the Company has established that the water supply impacts of the proposed facility operation are acceptable, based on consideration of water availability, impacts on watersheds and mitigation. 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

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[114] 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 Blackstone 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.

CRWA program 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 a community where potable water requirements are increasing, and in a basin area where demands 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 efforts 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 Blackstone officials and the Siting Board.

In summary, the Company has demonstrated that its maximum projected water withdrawals will fall within the Company's contractual limits for water at standard rates from the Town of Blackstone's municipal water supply system, and that the impacts of such withdrawals on the municipal water supply and on watersheds are acceptable, given the extent of mitigation offered by the proposed CRWA program.

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. The wetlands and wetland buffer zone impacts of the combined utility corridor which contains both the natural gas pipeline interconnect and the electric transmission interconnect are addressed in Section IV.D.3.1, below. Accordingly, the Siting Board finds that the environmental impacts of the proposed facility would be minimized with respect to wetlands and wetland buffer zone 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. The Company's proposed use of an on-site septic system, however, requires a waiver from 310 CMR 15.004(4). The record shows that the Company anticipates applying for the necessary waiver from the Blackstone Board of Health. Assuming the Blackstone Board of Health grants the Company's waiver request, the Company's wastewater and stormwater discharge plan will meet 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. The Siting Board notes that should ANP modify its wastewater and stormwater discharge plan due to a denial of its waiver request it would be required to notify the Siting Board, as discussed in Section V, below.

c. Visual Impacts

(1) Description

The Company submitted an evaluation of the potential visual impacts of the proposed facility at the proposed site (Exhs. BLK-1, at 6.7-3 to 6.7-12; HO-EA-1.1, and App. C; BLK-12.2, Vol. 1, at 7-5, Figs. 7-3 to 7-12). As part of its evaluation of visual impacts, the Company conducted viewshed analyses of the surrounding areas (Exh. BLK-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 and the overhead electric interconnect lines might be visible (Exh. BLK 12.2, Vol. 1, at Fig. 7-1). 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 (Exh. BLK-1, at 6.7-3 to 6.7-12; BLK 12.2, Vol. 1, at Figs. 7-3 to 7-12; HO-EV-5). The Company incorporated additional visual receptor locations at the request of EFSB staff and two intervenors (Exhs. HO-EV-10; BVCEP VS-7; BVCEP VS-8; TM-VS-6.1 to TM-VS-6.10). The Company presented photographs of existing views looking toward the proposed site under a range of seasonal conditions (Exhs. BLK-1, at Figs. 6.7-3 to 6.7-12; BLK-12.2, Vol. 1, at Figs. 7-3 to 7-

12). 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. BLK-1, at Figs. 6.7-3 to 6.7-12; BLK-12.2, Vol. 1, at Figs 7-3 to 7-12).

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-1.1, at 5-29; HO-EV-11; HO-EV-12; HO-EV-13). The Company indicated that over the course of a year, plumes of over 100 meters would be visible approximately 28 percent of daylight hours (Exh. HO-EV-12.1).[115] The Company stated that its plume visibility analysis excluded those daylight hours where the cloud ceiling was assumed to be below 5000 feet and when opaque sky cover was assumed to be 90 percent or more, arguing that such meteorological conditions would substantially reduce the impact of any visible stack plumes emanating from the proposed facility (Exh. HO-EV-12, Tr. 9, at 11-14). Finally, the Company described the MDEP standard with respect to the opacity 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-1.1, at 3-6).

The Company indicated that it had reviewed the Massachusetts Landscape Inventory, and had determined that no distinctive or noteworthy landscapes would be affected by the proposed facility (Exh. HO-EV-9). In addition, the Company assessed potential impacts of the proposed facility at properties in Blackstone that are listed on the National Register of Historic Places (Exh. HO-EL-19). The Company stated that views of the facility would be afforded from the East Blackstone Friends Meetinghouse located one-half mile south of the site, and also from the Southwick-Daniels Farm located approximately 1.75 miles to the west of the site (id.). The Company provided photographic exhibits depicting the potential viewshed impacts at both

[115] In its analysis, the Company assumed that there are 5058 daylight hours per year, and that the proposed facility would operate with steam augmentation for 38 days per year (Exh. HO-EV-12).

locations under both leaf-on and leaf-off conditions (Exhs. BLK-1 at Figs. 6.7-7 and 6.7-12; TM-VS-6.5 and TM-VS-6.10).

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 generally would be limited by surrounding land uses, terrain, vegetation and distance (Exh. BLK-1, at 6-68 to 6-71).

The Company indicated that both the facility structures and stacks would be visible from certain areas to the south of the facility along parts of Elm Street, including the Kimball property, and from adjacent properties (Exh. BLK-1, at 6-67, Figs. 6.7-1, 6.7-6, 6.7-7). The Company indicated that other residential neighborhoods to the south and west of the proposed site including Handy Road, Carol Lane, and Spruce Street, also would have views of the project stacks and rooflines[116] at some locations[117] (Exh. BLK-1, at Fig. 6.7-1, 6.7-8; Tr. 9 at 55).

The Company provided viewshed exhibits from roadway and residential locations to the east of the proposed site along Marzakowski Way and Bellingham Road which indicate that views of the upper portions of the project stacks and the interconnect lines would be present along a segment of Bellingham Road (Exhs. BLK-1 at Figs. 6.7-1, 6.7-4, 6.7-5; HO-J-E7, Att HO-E-7.1). The Company stated that views of the facility from residential areas to the north and west of the site, including Spruce Street in Blackstone and Pudding Stone Lane and Pine Needle Drive in Mendon, generally would be limited to views of the upper portions of the project stack

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116 The Company indicated that the overall height of the air cooled condensers and the turbine buildings would be 110 feet and 72 feet, respectively, and stated that these elements of the proposed facility would be the tallest structures at the site other than the two 180 foot tall stacks (Exh. BLK-1 at 6-68; HO-EV-8; HO-RR-53).

117 The viewsheds, aerial photographs and maps in the record indicate that the area south and southwest of the facility site encompasses extended open land, including cropland and fields (Exhs. BLK-1, at Figs. 6.5-1, 6.5-2, 6.7-3 to 6.7-12; HO-EL-1.1). In addition, although the area of open land is separated from the site by intervening woods, portions of the woods are in locations along the Mill River and thus are at lower elevations (Exh. BLK-1, at Figs. 6.5-1, 6.5-2, 6.7-2).

and the tops of the interconnect lines as seen through and above existing vegetation[118] (id. at Figs. 6.7-8 to 6.7-12; Exh. BLK-BEC-14, at 5-13). The Company provided additional viewshed exhibits from two other residential locations, one depicting the expected viewshed from the Higgins property located at the intersection of Blackstone and Elm Streets, and a second depicting the potential viewshed impacts at a second Spruce Street location closer to the proposed facility than the Spruce Street exhibit presented in the Company's Petition (Exhs. BVCEP-VS-7, BVCEP-VS-8).

The Company stated that the facility structures would be painted a neutral color, typical of modern industrial buildings, to minimize the visual impacts of the proposed facility (Exhs. BLK-1, at 6-68; Tr. 9, at 24 to 26). 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 (Exhs. HO-EV-7; Tr. 9, at 24 to 25).

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 (Tr. 9, at 19 to 20). 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 (Exh. HO-EV-4; Tr. 9, at 20-23). The Company also stated that the FAA had determined that no aviation lighting would be required on the facility stacks (Tr. 11, at 15). The Town of Blackstone Zoning Board of Appeals ("ZBA") considered the issue of exterior lighting in the context of a special permit application filed by ANP Blackstone Energy Company, and conditioned its approval of the special permit on specific restrictions with respect to exterior lighting on the proposed facility, including limitations on

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118 The tops of the electric interconnect lines also would be visible from the viewshed at Spruce Street near Blackstone Street, a point with higher elevation than at other nearby locations (Exh. BLK-BEC-14, at 5-13). The Company asserted that the views of the interconnection lines from the west would not be intrusive based on a distance to the proposed line of at least one-half mile, and a more prominent view of existing BECo 345 kV lines to the north (Exh. BLK-BEC-14, at 5-12).

height, directionality and intensity of lighting fixtures (Exh. HO-V-3.6, at ZBA Decision #1, p. 11).

The Company described its plans for on-site measures to mitigate visual impacts of the proposed facility at nearby residential locations (Exh. BLK 12.2, Vol. 1, at 7-5 to 7-6, Figs. 7-13 and 7-14). The Company stated that it intended to develop landscaping on disturbed areas of the site lying to the northeast and northwest of the proposed project footprint (id.). The Company indicated that its proposal included planting of trees, shrubs and grasses within four identified areas of the site and stated that, once established, trees planted in these areas would increase the vegetative buffer between the proposed facility and nearby residential areas (Exh. BLK-12.2, Vol. 1, at 7-5). The Company's proposed landscaping plans also contemplated the use of berms that would elevate new plantings above the existing grade to assist with visual screening (id. at 7-6, Figs. 7-13 and 7-14; Tr. 9, at 46-47).

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. 9 at 54 to 57). 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. 9 at 56 to 57). The Company indicated that it would consider requests for off-site mitigation of visual impacts for individual property owners in the vicinity of the proposed site, and would review all such requests on a case-by-case basis (Tr. 9, at 54 to 55).

(2) Analysis

The record demonstrates that the proposed facility would be significantly or fully screened from view in most directions as a result of its location in a sand and gravel area with wooded buffer from the surrounding community. The Company's analysis indicates that, at the majority of viewshed locations, views of the facility likely would be limited to the upper portions of the stacks as seen above existing trees.

However, the viewshed analysis does indicate the potential for pronounced visual impacts along sections of Elm Street and in nearby residential areas located primarily to the south of the proposed site. In addition, in some of the viewshed areas, notably Bellingham Road to the east and western portions of Spruce Street and Colonial Drive to the west, project impacts would include views of the electric interconnect lines extending along the horizon north of the site in combination with views of the generating facility itself.

The Company's analysis of plume visibility for the proposed facility indicates that visible exhaust plumes of varying lengths would be present with operation of the facility. These plumes likely would be visible from areas where views of the facility structures themselves would be significantly limited or non-existent. The Company's plume visibility analysis assumed the base case scenario of just over 38 days per year of steam augmentation, considered visibility for daylight hours only, and excluded those hours where ambient meteorological conditions would tend to reduce the visual impact of any visible exhaust plume. Given these assumptions, the record indicates that visible plumes of 100 meters or more in length would occur during approximately 28 percent of daylight hours. The Company has provided evidence and testimony which confirms that steam augmentation is a contributing factor to plume visibility. 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 it intends to seek input from its EPC contractor, local officials and other concerned parties on issues such as building color, the effect of nighttime lighting at the site, and other related aesthetic concerns, 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, 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 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. ANP-Bellingham Decision, EFSB 97-1, at 128; Millennium Power Decision, EFSB 96-4, at 140; Dighton Power Decision, EFSB 96-3, at 47-48; Berkshire Power Decision, 4 DOMSB at 395. Here, the Company has expressed a willingness to consider mitigation of visual impacts at individual properties in the vicinity 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 generating facility and related facilities at affected residential properties and at roadways and other locations within one mile of the proposed facility, as requested by individual property owners 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 Blackstone and Mendon, 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.

Given the extended open viewshed areas along Elm Street and nearby locations south and southwest of the facility site, and the potential for pronounced visual impacts on residences and roadways, the Siting Board encourages ANP to work with affected residents and officials on a coordinated basis, as applicable, to address any off-site mitigation issues. Such a coordinated approach could encompass roadway plantings as well as plantings on private properties. In addition, if mitigation requests arise in areas affected by both the generation facility and the electrical interconnect line, ANP should work with affected residents and officials to develop reasonable approaches to mitigation that would address both concerns.

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.

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. BLK-1, at 6-81, 6-97; BLK-12.2, Vol. 1, at 9-17). 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. BLK-1, at 6-97; HO-EA-1.1, App. D at 37, 38; HO-EN-9). The Company further stated that the worst-case noise impacts during on-site construction activity would be intermittent and temporary in nature, and that while noise from construction traffic would be noticeable at nearby residences, it would not be significantly greater than noise from existing traffic flow in the area (Exh. HO-EA-1.1, App. D, at 14 to 17).

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. 7, at 39). The Company stated that there are various measures of noise, and indicated that the MDEP Standard which limits allowable noise increases at residences and property lines 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. BLK-12.2, Vol. 1, at 9-3; Tr. 7 at 127). 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}") (Exh. BLK-12.2 Vol. 1, at 9-3).

To define the environmental impacts of the proposed project with respect to noise, the Company provided analyses of existing noise levels and quantified the expected impacts of both construction activity and operational noise in the vicinity of the proposed site (Exhs. BLK-1, at 6-87, 6-92; HO-EA-1.1, App. D, at 16, 37). To establish existing background noise levels, the Company conducted surveys at six distinct locations at various distances and directions from the proposed site (Exh. BLK-1, at 6-85 to 6-87). The Company stated that it selected the six noise monitoring locations ("NMLs") in order to obtain an adequate spatial representation of the ambient noise environment that would form the basis for modelling project-related noise increases at the nearest affected residences and property lines (id. at 6-85). The Company stated that the six NMLs were located as follows: (1) along Elm Street at the entrance to the existing Kimball Sand and Gravel facility (NML-1), representative of residences located southwest of the proposed site; (2) at the cul-de-sac on Spruce Street to the west of the site (NML-2), representative of the closest residential locations to the west of the site; (3) at the south end of Maple Leaf Lane on the Mendon/Blackstone line (NML-3), representative of the closest residential properties to the northwest of the site; (4) at the southernmost extent of Pine Needle Drive in Mendon (NML-4), representative of the closest residences to the northeast of the site; (5) along Bellingham Road at the Kimball site access easement (NML-5), representative of the closest residences to the east of the site; and (6) on the proposed site in the vicinity of the project footprint (NML-6) (id. at 6-85 to 6-87).[119]

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. BLK-12.2, Vol. 2, App. C). The Company noted that for each NML, the quietest ambient levels were observed during the nighttime monitoring periods (Exh. BLK-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 closest residence, which the Company stated would be located on Spruce Street approximately 1300 feet northwest of the proposed facility footprint (Exhs. BLK-1, at 6-92; HO-EA-1.1, App. D, 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. BLK-1, at 6-92 to 6-93; Tr. 7, at 47, 58). The Company estimated that maximum levels of construction noise would be 61 dBA at the closest residence and that such levels likely would occur during the excavation and finishing phases of construction (Exh. BLK-1, at 6-92). The Company asserted that during the ground clearing, foundations, and steel erection phases, construction noise levels at the nearest residence generally would range from 50 dBA to 57 dBA (id.).

With respect to noise from construction traffic, the Company stated that noise increases would be noticeable at nearby residences, especially those along Elm Street, but that the impact would not be significant compared to that from the 1800 vehicles per day that currently use Elm Street (Exh. BLK-1, at 6-93). The Company did, however, assess the traffic noise impacts of the proposed 12:00 a.m. departure of a second construction shift (200 vehicle trips) from the facility

[119] The Company noted that its ambient noise measurements were conducted during periods of inactivity at the Kimball sand and gravel facility (Exh. HO-EN-2). The Company therefore asserted that its ambient measurements were conservative because, when operating, the sand and gravel facility is a major source of noise in the community (id.).

site. The Company stated that during the period when vehicles would be exiting the site, noise levels at residences along Elm Street could increase by up to 5 dBA (Tr. 7, at 60-61).

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. TM-Noise-6; Tr. 7, at 65-69). 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 50 dBA during these events (id.; Tr. 7 at 66).[120]

The Company indicated that it would implement steps to mitigate construction noise, including: (1) compliance 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. BLK-1, at 6-93; BVCEP-NO-8).[121]

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 four residential receptors and three property line receptors (Exh. HO-EA-1.1, App. D, at 37). Based on its analysis, the Company stated that during facility operation, daytime L_{90} increases at residential receptors would be 5 to 8 dBA, and nighttime L_{90} increases would be 6 to 10 dBA, thereby satisfying the MDEP Standard at the most affected residential receptors (id.). The Company further stated that

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120 The Company stated that it would inform town officials and area residents in advance about steam release events so that any noise increases relating to these events would be readily identifiable as such (Exh. TM-Noise-6; Tr. 7, at 67).

121 The Company noted that Town of Blackstone regulations (Chapter 98, Sec. 6, Code of the Town of Blackstone) would limit nighttime (11:00 p.m. to 6:00 a.m.) noise impacts to 55 dBA at off-site locations within 100 feet of the site boundary (Exh. BVCEP-NO-8). The Company stated that it expected to comply with this regulation as noisy construction activities at the site would be limited to daytime hours (id.).

daytime L_{90} increases at the property lines of the proposed site would range from 11 to 21 dBA, with greater increases and exceedances at night (id.).

With respect to operational noise impacts at the property lines of the proposed site, the Company stated that only daytime increases were considered where abutting lands would be unsuitable for residential development (Exh. HO-EA-1.1, App. D, at 37). The Company indicated that combined facility plus ambient noise would be 50 dBA at PL-1, resulting in a daytime increase of 18 dBA at the northwest property line,[122] and would be 53 dBA at PL-3, resulting in a daytime increase of 21 dBA at the south property line (id.). The Company projected combined facility plus ambient noise levels of 43 dBA at PL-2, resulting in a daytime increase of 11 dBA at a point along the site boundary that would be roughly east of the proposed facility (id.). The Company indicated that location R-3, the closest residential property line to the north of the facility site, effectively provides a fourth property line receptor point at the Blackstone / Mendon corporate boundary (Tr. 7, at 102-103). The Company stated that combined facility noise plus ambient at R-3 would be 38 dBA, resulting in a nighttime increase of 10 dBA at this location (Exh. HO-EA-1.1, App. D, at 37; Tr. 7, at 105).

The Company concluded that facility noise levels would produce exceedances of the 10-dBA limit along a portions of the west, south and eastern property lines and that the project would therefore require a waiver of the applicable MDEP noise standard[123] (Exhs. HO-EN-9; TM-Noise-5). 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 a prospective agreement between ANP and the landowner, Mr. Kimball,

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122 The Company indicated that the nighttime increase over ambient at PL-1, the northwest property line would be 22 dBA (Exh. HO-EN-6).

123 The Company noted, however, that noise levels at the property lines would be in compliance with Code of the Town of Blackstone (Chapter 98) which allows noise sources to result in continuous exterior noise levels of up to 55 dBA at a distance of up to 100 feet from the property line (Exh. BVCEP-NO-8). The Company stated that, during operation of the proposed facility, estimated plant noise at off-site locations would not exceed 53 dBA (Exhs. HO-EA-1.1 at 37; BVCEP-NO-8).

that would place noise encumbrances on any future residential development on affected lands (Exhs. HO-EN-9; TM-Noise-5; BLK-12.4 at 3-103; HO-RR-35(Rev.); Tr. 7 at 169-171).

With respect to operational noise impacts at residential locations, the Company indicated that nighttime L_{90} levels at the nearest residences would range from 35 dBA to 39 dBA (Exh. HO-EA-1.1, App. D, at 37). Based on its noise analysis, the Company identified receptors R-2 and R-3, residential neighborhoods on Spruce Street and Laurel Road in Blackstone, and on Pudding Stone Lane in Mendon, respectively, as the residential locations most affected by noise[124] (id.). The Company stated that nighttime L_{90} noise in the vicinity of location R-2 was measured at 29 dBA and that facility noise would be 38 dBA (id.). The Company indicated that the resulting nighttime ambient plus facility noise would be 39 dBA, and would therefore result in an L_{90} increase of 10 dBA at this location (id.). The Company stated that, in the vicinity of location R-3, the nighttime L_{90} noise was measured at 28 dBA, and that facility noise would be 38 dBA (id.). The Company calculated that the combined L_{90} noise at location R-3 would be 38 dBA, an increase of 10 dBA (id.).[125]

As an offsetting factor, the Company's witness, Mr. Keast, testified regarding certain assumptions used in the noise analysis that would tend to overstate actual noise impacts (Tr. 7, at 134-138). Mr. Keast explained that the noise impact model incorporated conservative assumptions with respect to several variables, including: (1) meteorological conditions; (2)

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124 The Company stated that the distance from the closest facility noise source to the residential receptors would be 1300 feet to location R-2, and would be 1460 feet to location R-3 (Exh. HO-EA-1.1, App. D, at 30, 32).

125 The Company indicated that the closest residences to receptors R-2 and R-3 would be located 100 to 300 feet further from the facility than the corresponding receptors -- placed on the site boundary with the affected residential areas (Tr 7, at 83-84; Exhs. HO-EL-1.1, HO-RR-30). The Company indicated that, with the additional distance from the proposed facility, noise levels would be further attenuated at the most affected residences; in all but one case -- a residence on Pudding Stone Lane located near the rear of the lot -- the Company indicated that affected residences would be at least 250 feet further from the facility than the corresponding receptor, and the expected nighttime increase in L_{90} noise at those residences would be 9 dBA (Tr. 7, at 83-84; Exh HO-RR-30).

terrain changes and vegetative screening; and (3) ground reflectivity, and concluded their effect would often be to overstate the actual L_{90} noise increases attributable to the proposed facility (Exh. HO-EN-8; Tr. 7, at 134-138, 143).

To further characterize the existing noise environment, and the expected impact of the facility, the Company provided estimated day-night sound levels ("L_{dn}"),[126] with and without the proposed facility, for the various residential and property line receptors (Exh. HO-EN-17). The Company stated that L_{dn} levels at all modelled receptors were currently 5 dBA or more below the USEPA's 55 dBA threshold[127] (id.). The Company estimated that at the most affected residence, location R-1, the existing L_{dn} is 49 dBA, and that facility noise would increase the L_{dn} by one decibel to 50 dBA (id.). ANP stated that L_{dn} levels at the other residential receptors ranged from 45 to 47 dBA, and that facility noise would result in increases of 1 to 2 dBA (id.). The Company explained that its initial L_{dn} measurements did not consider noise related to operations at the nearby sand and gravel mining facility (id.). At the request of Siting Board staff, the Company performed an additional analysis that included noise generated during sand and gravel operations (Exh. HO-RR-34).[128] The Company indicated that including noise from the sand and gravel

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126 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. 7, at 44).

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

128 The Company explained that it derived the estimated L_{dn} levels for each receptor point by measuring noise from the sand and gravel facility at the entrance to the Kimball facility. The Company then used that value (55 dBA) to calculate individual L_{dn} values for each of the receptor points by scaling from the measured level using a rule-of-thumb (6 dB per doubling of distance) (Exh. HO-RR-34; Tr. 7, at 40).

facility causes slight increases in L_{dn} levels measured at residential and property line receptors, but that the addition of operational noise from the proposed facility would not change overall L_{dn} levels at any receptor except at location R-4, where the L_{dn} would increase by one decibel from 46 dBA to 47 dBA (id.).

With respect to property line impacts, the Company stated that the highest 24-hour equivalent noise level ("L_{eq}") would be 53 dBA at location PL-3, on the southeast side of the proposed site (Exh. HO-EA-1.1, App. D, at 37). The Company indicated that this level would be 22 dBA less than the 75 dBA limit recommended by USEPA to protect hearing, and 32 dBA less than the threshold level of the Occupational Safety and Health Administration for worker exposure over an eight-hour day (Exh. HO-EA-1.1, App. D, at 38).

The Company asserted that the proposed facility is designed with careful consideration of measures to mitigate noise impacts to the surrounding community (Exhs. BLK-1, at 6-71; HO-EA-1.1, App. D, at 39). 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 with splitter mufflers, if required, 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, as required, around the exhaust ducts and HRSGs; (7) acoustic enclosure of the proposed gas compressor building; (8) noise control for other outdoor electrical and mechanical equipment, including pumps; and (9) special silencing provisions for the circulating cooling water coolers (Exhs. BLK-1, at 6-93 to 6-95; HO-EA-1.1, App. D, at 39). 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 $11.1 million for mitigation of noise impacts from the proposed facility (Exh. HO-EN-19.1).[129] To

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[129] The Company explained that the $11.1 million figure consists of approximately $3 (continued…)

further illustrate the extent of noise mitigation that is projected for the proposed facility, the Company compared the cost of mitigating noise impacts at the proposed facility to that at its recently approved ANP-Bellingham facility -- a project that is similar to the proposed facility in many respects (Exhs. HO-EN-16; Company Brief at 154). The Company stated that the comparable cost of noise mitigation for the ANP-Blackstone project would be $3.5 million more than that for the ANP-Bellingham project (id.).

In response to requests from the Siting Board staff, the Company identified and considered the cost-effectiveness of various measures to further mitigate noise impacts from the proposed facility, including additional noise mitigation equipment, and consideration of facility design or layout changes (Exhs. HO-EN-5; HO-EN-14; HO-RR-29; HO-RR-31; HO-RR-32; HO-RR-52; Tr. 7, at 96-102, 109-125).

The Company considered two specific combinations of noise mitigation measures: (1) an option that would reduce the maximum projected nighttime L_{90} increase from 10 dBA to 9 dBA at the most affected residential receptor at Pudding Stone Lane ("Option 1"), at an additional cost of approximately $1.8 million, representing a 16 percent cost increase for noise mitigation[130] (Exh. HO-RR-52); and (2) an option that would reduce the maximum projected nighttime L_{90} increase at the residential receptors to 7 dBA ("Option 2"), at an additional cost of approximately $7.4 million, representing a 66 percent cost increase for noise mitigation (Tr. 7, at 98-99).

As an alternative to the incorporation of additional noise mitigation technologies, the Company also considered moving the facility footprint to the south in order to reduce noise impacts at residential properties located along the Mendon / Blackstone line (Exh. HO-RR-32;

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[129](…continued)
million for the ABB "reference" plant, plus $8.1 million in additional noise mitigation features for this particular facility (Exhs. HO-EN-19.1; HO-RR-27; Tr. 7, at 97).

[130] Based on further analysis of the noise modelling results, and the testimony of the Company's witness, Mr. Keast, the Siting Board concludes that this option would reduce the L_{90} increase at the most affected residence to 9 dBA, and would result in L_{90} increases of approximately 8 dBA at the 12 remaining residences on Pudding Stone Lane (Exh. HO-RR-30).

Tr. 7, at 116-125). The Company estimated that moving the facility footprint to the south, into the area originally designated for the oil storage tanks, would reduce the expected L_{90} increase at location R-3 by one decibel (Exh. HO-RR-32). However, the Company noted that noise impacts at R-1 would increase by one decibel, and no benefit would be obtained relative to location R-2, the second residential area where L_{90} increases would approach 10 dBA (id.). The Company also explained that moving the plant location would involve significant design, engineering and permitting costs, and would result in significant delays to the project schedule (id.).

The Company stated that it did not propose to incorporate any of these noise mitigation options into the pre-construction design of the proposed facility, but maintained that additional noise mitigation measures typically would be available for incorporation during final facility design to complete the overall noise control package for the proposed facility (Tr. 7, at 144-148).[131]

(2) Analysis

In past decisions, the Siting Board has reviewed the 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.

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131 The Company stated that upon plant commissioning, the noise impacts of the proposed facility typically would be tested for compliance with the terms and conditions of the EPC contract (Tr. 7 at 143-151). The Siting Board also notes that the Blackstone ZBA has conditioned its Special Permit such that ANP would provide funds to support monitoring and evaluation of operational noise impacts by the town (Exh. HO-V-3.6, at Decision #1, at 10, 13).

The Company's noise model indicates that, at two residential receptors located at the north and west property lines of the proposed site, facility operation would result in nighttime L_{90} increases of 10 dBA above existing ambient levels, which range from 28 to 29 dBA. Thus, the proposed facility would just meet the MDEP Standard at the edge of two residential areas -- one located on Pudding Stone Lane to the north of the site, and the other located along Spruce Street and Laurel Road to the west of the site. The modelling results indicate that, during the day, facility operation would result in L_{90} increases of 8 dBA or less at all residential receptors.

With respect to noise impacts in other areas adjacent to the property line, lands to the south and southeast of the proposed site that either are vacant, or are host to an industrial use (sand and gravel mining), would have nighttime and daytime L_{90} increases that would be well above 10 dBA. Facility noise levels also would exceed the MDEP Standard on portions of one parcel to the immediate west of the site which is zoned residential, but which the Company has asserted would be unavailable for residential development due to the presence of wetlands. To the east, considerable buffer to residential uses is provided by the dimensions of the site itself, and by abutting uplands that presently are undeveloped.

With respect to the impacts of facility noise on nearby residences, the record indicates that the combined (i.e., facility plus ambient) nighttime L_{90} levels of 38 to 39 dBA at the site boundary residential receptors -- an increase of 10 dBA over the existing, very quiet, ambient levels -- still would be well below worst case noise levels of other recently-approved gas-fired generating facilities.[132] With the exception of one of the residences to the north of the site, which is 100 feet further from the facility site than the corresponding receptor, the actual locations of residences are 250 to 300 feet further from the proposed facility than the receptors positioned on the site boundary. Therefore, the actual L_{90} noise increases at residences would be at least one

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132 In one recent case, L_{90} levels with facility operation ranged from 37 to 40 dBA at residential receptors. Dighton Power Decision, EFSB 96-3, at 52. However, in three earlier gas-fired generating facility cases, operational L_{90} levels at residential receptors ranged from 48 to 51 dBA. Enron Decision, 22 DOMSC at 208; MASSPOWER, Inc., 20 DOMSC at 301, 390; NEA Decision, 16 DOMSC at 401-402.

decibel less than modelled -- or a maximum of 9 dBA -- in all but one case.[133] Further, as indicated by the Company, actual L_{90} noise increases are likely to be lower than calculated based on modelling, due to conservative model assumptions. Existing residential L_{dn} levels would be essentially unchanged with operation of the proposed facility, and, at a maximum of 49 dBA, would remain well below the USEPA 55-dBA guideline for residential areas.

The Siting Board recognizes that the MDEP Standard represents a statewide policy on maximum allowable noise increases. Consistent with its mandate to minimize environmental impacts and costs, the Siting Board seeks to ensure that all cost-effective noise mitigation is included in the design of generating facilities, rather than merely to substantiate that a proposed project would comply with MDEP standards. In two prior cases, the Siting Board ordered facility developers to provide noise mitigation beyond that proposed in order to hold L_{90} increases at residences to 7 to 8 dBA at residences, largely because existing ambient noise levels were high. Millennium Power Decision, EFSB 96-4 at 156; Silver City Decision, 3 DOMSB, at 331, 367-368. In Millennium, the Siting Board required the proponent to hold modelled L_{90} increases at residences to 7.5 dBA, citing concerns that a high L_{dn} level of 67.5 dBA was indicative of an already noisy environment. In Silver City, the Siting Board ordered additional noise mitigation to address impacts at two residential receptors which, although at or below the USEPA guideline for L_{dn} noise, were to be affected by periodic daytime noise from fuel handling activities, resulting in an L_{dn} increase of as much as 3 dBA at one of the two receptors. In contrast, the Siting Board has accepted a modelled L_{90} increase of 10 dBA where nighttime

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133 The Company testified that it is likely that all property owners in neighborhoods affected by significant noise increases from the proposed facility were signatories to a settlement agreement with the Company. ANP-Blackstone entered into two such agreements with area residents; (1) a "comprehensive agreement" designed to address issues of property value compensation, and (2) a "global settlement" with BVCEP, an intervenor that withdrew from the proceeding pursuant to the settlement.

ambient levels were low, L_{dn} levels were not at issue, and additional noise mitigation did not appear to be cost-justified. Dighton Power Decision, EFSB 96-3 at 54.[134]

Here, ANP has demonstrated that, during facility operation, noise levels at residential locations would be consistent with the lower end of a range of residential L_{90} levels reviewed in recent cases. Furthermore, L_{dn} levels at residential receptors are well below 55 dBA and would remain essentially unchanged with operation of the proposed facility. In order to comply with the MDEP standard at nearby residences, ANP-Blackstone has committed to noise mitigation measures totalling \$11.1 million. Further noise mitigation that would reduce maximum nighttime L_{90} increases by one decibel at the nearest residential receptor would cost an additional \$1.8 million[135]; additional noise mitigation that would reduce nighttime L_{90} increases to 7 dBA or less at all residential receptors would cost an additional \$7.4 million.[136] These costs are significantly greater than in several previous cases where the Siting Board had required proponents to design additional mitigation for noise impacts. Millennium Power Decision, EFSB 96-4, at 156; Berkshire Power Decision, 4 DOMSB at 442; Silver City Decision, 3 DOMSB at 367.[137] For cases with noise environments most similar to that at the proposed site --

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[134] In Dighton, consistent with terms developed in record conferences held after the close of hearings, the Siting Board required noise testing to be conducted within six months of commercial operations to determine whether operational noise impacts would exceed 8 dBA at affected residences. Dighton Power Decision, EFSB 96-3, at 54-58. In the event that actual L_{90} increases at residences were found to be 8 dBA or greater, the Siting Board ordered that DPA undertake additional noise mitigation (either off-site, on-site, or both) to hold residential L_{90} increases to below 8 dBA. Id.

[135] Option 1 would also reduce the nighttime L_{90} increases from 9 dBA to 8 dBA at 12 other residences in the same neighborhood.

[136] The Company also analyzed the possibility of moving the facility footprint south to reduce facility noise impacts at the Blackstone/Mendon border. Based on the record evidence, the Siting Board concludes that the engineering and permitting delays and additional costs resulting from such a redesign make this option unfeasible.

[137] In Millennium, the Siting Board required additional mitigation to reduce the L_{90} increase at the most affected residences from 10 dBA to 7.5 dBA, at an additional cost

(continued…)

very quiet backgrounds at some receptors and no exceedances of the USEPA guideline at any receptor -- the cost of additional mitigation ordered by the Siting Board has been less than $500,000. We also recognize that the noise environment at the proposed site requires the Company to install an extensive set of noise mitigation measures simply to comply with the MDEP Standard.

In summary, the Company has committed to an extensive baseline noise mitigation package, at a cost of $11.1 million, in order to comply with the MDEP Standard at a site where ambient noise levels are very low. The proposed facility, once operational, would result in L_{90} levels, of 38 to 39 dBA at residential receptors -- levels that are among the lowest reviewed by the Siting Board in any generating facility case. Furthermore, the proposed facility would have only a minimal impact on residential L_{dn} levels that currently are 6 dBA or more below the USEPA guideline. Finally, the record indicates that the cost to reduce facility noise at residences by one decibel would be $1.8 million, as compared to $500,000 for a two decibel reduction in Silver City, and $1 million for a 2.5 decibel reduction in Millennium.[138]

Therefore, after a balanced consideration of the evidence in this case, the Siting Board concludes that 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

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[137](…continued)
of approximately $1.0 million. Millennium Power Decision, EFSB 96-4, at 156. In Berkshire, the Siting Board directed the proponent to hold L_{90} increases to within the MDEP standard on abutting vacant lands that would be suitable for nighttime occupancy, at a cost of approximately $156,000. Berkshire Power Decision, 4 DOMSB at 443. In Silver City, the Siting Board required the proponent to reduce L_{90} impacts at specified residential locations by 2 dBA at a cost of approximately $500,000. Silver City Decision, 3 DOMSB at 367.

[138] The Siting Board recognizes that, in general, a larger facility could support larger expenditures for mitigation of environmental impacts. Regardless, the Siting Board, consistent with its mandate, will require such expenditures only when the specific circumstances of a case dictate that additional mitigation would be cost-effective.

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. ANP-Bellingham Decision, EFSB 97-1, at 140-141; 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. The Siting Board directs the Company to implement noise mitigation for the proposed facility consistent with attaining a modelled L_{90} noise increase of 10.0 dBA or less at the site boundary residential receptors.

Accordingly, the Siting Board finds that with the implementation of proposed mitigation, including measures to limit modelled L_{90} noise increases to 10.0 dBA or less at the site boundary residential receptors, 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.

e. Traffic

(1) Description

The Company asserted that traffic impacts resulting from the construction and operation of the proposed facility at the proposed site would be minimized consistent with Siting Board standards (Exh. BLK-1, at 6-120; Company Brief at 156). 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 examined the expected traffic flows and impacts that would result from both facility construction and operation (Exh. BLK-1, at 6-97).

The Company indicated that existing peak commuter traffic periods in the vicinity of the proposed site are from 7:00 a.m. to 8:00 a.m., and from 5:00 p.m. to 6:00 p.m. (Exh. BLK-12.2, at 6-2). The Company stated that, for purposes of modelling construction-related traffic impacts, it assumed a three shift construction schedule[139] which represents the maximum number of workers projected to be on-site during the construction period, as follows: (1) a civil/construction shift (200 workers) from 7:00 a.m. to 5:30 p.m., (2) a mechanical/electrical shift (600 workers) from 6:00 a.m. to 4:00 p.m., and (3) a second mechanical shift (200 workers) from 4:00 p.m. to 12:00 a.m. (Exh. BLK-12.2, Vol. 1, at 6-2). The Company also assumed that all of the first shift civil/construction workers would arrive during the morning peak period, and that all of those workers would depart during the evening peak (Tr. 6, at 33-34).[140] The Company indicated that its assumptions with respect to shift timing would result in a conservative estimate of traffic impacts because, in actuality, shift changes at the proposed site would be generally outside of local peak hours (id.).

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139 The Company explained that its initial traffic impact assessment for the project had assumed a two shift schedule, in which worker arrivals and departures would have coincided more closely with peak commuter periods (Exh. BLK-12.2, at 6-2).

140 The Company indicated that its analysis of construction related traffic assumed an occupancy rate of 1.11 workers per vehicle, with expected ride-sharing, and noted that the allowance for ride-sharing was conservative (Exh. BLK-12.2, at 6-2).

The Company provided a model timetable for construction of the proposed facility, and indicated that the most intensive construction activity at the site would occur from months 13 to 18 of the planned 20.5 month construction schedule (Exh. HO-RR-15; Tr. 6, at 37-38). The Company stated that during the peak months, the maximum number of construction workers employed on the site at any one time could be up to 860 persons, but that significantly fewer than the maximum number of laborers would be present for the majority of the construction period (id.). The Company therefore asserted that for much of the 20.5 month period, construction related traffic impacts would be less than those identified in the traffic impact analysis (Exhs. BLK-1, at 6-107; HO-RR-15.1; Tr. 6 at 24, 37-38).

The Company identified four key roadway intersections that might be affected by construction-related traffic, and presented a comparison of expected peak-hour levels of service ("LOS")[141] with and without the proposed facility at those intersections (Exh. BLK-1, at 6-103). Of the four intersections, the Company indicated that two would function as the main gateway intersections to the proposed site: (1) the Route 126 / Elm Street intersection to the southeast of the proposed site; and (2) the Elm Street / Blackstone Street intersection to the northwest of the proposed site[142] (Exhs. BLK-1, at Fig. 6.9-4; BLK-12.2, at 6-1, 6-7). The Company stated that the unsignalized Route 126 / Elm Street intersection currently operates with delays of greater than 120 seconds during peak commuter periods, and therefore is rated at LOS F for those

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141 The Company stated that LOS is a measure of the efficiency of traffic flow at a location (Exh. BLK-1, at 6-101). 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 6-102).

142 The two other intersections studied were Bellingham Road and Elm Street, and Park Street and Elm Street. Both Bellingham Road and Park Street are side streets that connect with Elm Street between Route 126 and the facility access road. The Company estimated that construction related traffic impacts to these side streets would be minor, resulting in slightly increased delays for some movements during the peak hours (Exh. BLK-1, at 6-112).

periods (Exh. BLK-1, at Table 6.9-2).[143] The Company indicated that the Elm Street / Blackstone Street intersection currently exhibits minimal delays with a rating of LOS A or B during peak hours, and would continue to function at these same levels during the construction period (id.).

The Company also assessed peak hour LOS for the unsignalized intersection of the proposed site access driveway with Elm Street and projected that traffic conditions during construction would be acceptable (LOS A or B) for both morning and afternoon peak periods (Exh. BLK-1, at 6-112).

The Company recognized that construction of the proposed facility would increase traffic at the Route 126 / Elm Street intersection, and stated that it would mitigate the impact 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 that location during the morning and afternoon shift changes (Exh. BLK-1, at 6-113). The Company also stated that its construction workforce would be discouraged from using residential side streets (Exhs. BLK-1, at 6-103, 6-113; HO-ET-2). The Company explained that it would institute appropriate policies among its workforce to direct construction-related traffic away from alternative routes that would affect residential streets and neighborhoods (Exhs. HO-ET-2; BVCEP-T-7).

The Company indicated that, in addition to employee worker trips, there would be 22 delivery vehicle round trips per day during the peak construction period (Exh. BLK-1, at 107).[144] The Company also noted that the proposed project would share access to Elm Street with the Kimball Sand and Gravel Company, which creates an average daily traffic flow of approximately

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143 The Company stated that redesign of the Route 126 / Elm Street intersection might effectively address long-term congestion at the intersection, but that the impacts of the proposed project would be of shorter duration and would call for short-term a mitigation strategy (Tr. 6, at 26-29). The Company noted that Route 126 is a state road, and that any initiative to redesign or signalize its intersection with Elm Street would be a matter for the state and local community to address (id. at 28).

144 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, four delivery round-trips were assumed to occur during both the morning and afternoon peak hour periods (Exh. BLK-1, at 107).

190 truck trips per day (Exhs. BVCEP-T-12; BLK-1, at 6-98). ANP noted that its analysis accounted for traffic activity relating to the existing sand and gravel operations (id.).

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 (Exhs. BLK-12.2, Vol. 1, at 6-8; Tr. 6, at 39). The Company stated that its EPC contractor, ABB, would be responsible for conducting road and bridge surveys to ascertain that roadway widths, turning areas and bridge capacities along its proposed delivery route would be adequate[145] (Exhs. BLK-12.2, Vol. 1, at 6-7; Tr. 6, at 39-50). The Company indicated that ABB would review the capacity of at least one bridge along the proposed delivery route[146], and that a determination of the need for any roadway improvements would be made after ABB completed its study, but before final placement of the EPC contract (id.).

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. BLK-1, at 6-114). The Company stated that, once operational, the proposed facility would have insignificant impacts on local traffic conditions, and that vehicle trips related to the proposed facility would constitute one percent or less of peak hour volumes at the gateway intersections (id. at 6-120). The Company asserted that no additional traffic mitigation would be necessary during the operational lifetime of the proposed facility (id.).

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145 The Company stated that, based on information available from ABB, the probable route for such deliveries would be from I-495 to Route 140 west, to Route 126 south, continuing through the Town of Bellingham to the junction with Elm Street, and then following Elm Street to the project driveway (Exh. BLK-12.2, Vol. 1, at 6-7; BLK-12.4, at 3-25).

146 The Company asserted that bridge improvements, if required, would be subject to review and permitting by MHD, but likely would be of a temporary nature and typically could be performed without causing significant interruption of normal traffic flow (Exhs. BLK-12.4, at 3-25; Tr. 6, at 42-50).

(2) Analysis

The record indicates that there would be no change in LOS classification at the Route 126 / Elm Street and Elm Street / Blackstone Street intersections as a result of either construction or operation of the proposed facility. However, the record indicates that the Route 126 / Elm Street intersection currently exhibits poor traffic flow (LOS F) at peak travel times. Consequently, the Siting Board is concerned that the existing congestion at an already failing intersection would be exacerbated by traffic activity associated with the proposed project, particularly during the months of peak construction activity at the site. Additionally, the Company's analysis indicates that access to Elm Street from Bellingham Road and Park Street, two side streets in the project area, would be slightly affected by construction traffic from the proposed project.

To minimize traffic impacts from construction of the proposed facility, the Company has indicated that it would: (1) schedule daytime work shifts and shift changes to occur outside of the identified local peak traffic hours; and (2) coordinate with state and local authorities to place uniformed officer controls at the Route 126 / Elm Street intersection during periods of maximum flow of construction traffic. The record indicates that the Company has taken steps to mitigate the impact of construction traffic by proposing a three shift work schedule to stagger daytime shifts and avoid peak hour shift changes. The Company also has identified other traffic mitigation measures that 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. Although the Company has identified a likely route for such deliveries, the Company has not yet determined whether road or bridge improvements would be needed to accommodate deliveries of very large plant components. If significant improvements are needed, additional traffic impacts could result from the roadwork.

Therefore, the Siting Board directs ANP to work with the MHD and the Towns of Bellingham and Blackstone[147] to develop and implement a traffic mitigation plan which addresses scheduling and roadway and bridge construction or improvement. This plan should, to the extent practicable, include scheduling of arrivals and departures of construction related traffic, including but not limited to construction labor, deliveries of materials, equipment, and plant components, so as to avoid daily peak travel periods in affected areas. The plan 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.

With respect to traffic impacts during facility operation, the Company has demonstrated that no adverse traffic conditions would result from operation of proposed facility at the proposed site.

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

f. Safety

ANP stated that to help insure safety at the proposed facility it would: (a) adhere to good engineering practices 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) monitor operations on a regular basis (Exh. BLK 12.2, at 3-22)).

In addition, the Company stated that it would incorporate the following safety features into the facility design: (a) containment basins or dikes for all hazardous material storage

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[147] The Siting Board notes that, should delivery routes include roadways in towns other than Bellingham and Blackstone, officials of those municipalities should be consulted in developing the traffic mitigation plan for the project.

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 protection system; and (f) fencing around the proposed site to prevent unauthorized individuals from gaining access to the facility (id. at 3-22 to 3-23).

(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 (id. at 3-22). The Company stated that the transfer of ammonia from delivery vehicles would occur within a concrete diked containment area (id.). 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. EFSB-31; Tr. 6 at 89 to 91).

The Company provided computer modeling data which shows that the concentrations at the fence line from an ammonia spill would be 79 ppm after 30 minutes and 69 ppm after one hour, even without the containment building (Exh. HO-RR-21). The Company noted that these concentrations are below the Immediately Dangerous to Life or Health ("IDLH") threshold of 500 ppm (id.; Exh. HO-EA-1.1, at 5-32 to 5-34). 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 (id.).[148]

The Company asserted that ammonia would be the only chemical delivered to the site in bulk shipments (Exh. HO-ES-5). All other chemicals would be delivered in small shipments via common carrier in approved United States Department of Transportation ("DOT")

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148 The analysis showed that if ambient wind speeds were low, the dispersion of ammonia vapor would be similar to the worst case calculated for the non-enclosed system. However, if ambient wind speeds were high, the emission rate would still be small, the dilution rate would be greater and the resulting ambient concentrations should be lower (Exh. HO-EA-1.1, at 5-32 to 5-34).

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 store hazardous materials in a manner consistent with the DOT's Specific Material 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-7; Tr. 73, at 8 to 9). The modeling results indicated that fogging and icing would not occur under either scenario (Exh. HO-ES-7; Tr. 73, at 8 to 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). The Company also stated that it would develop a separate contingency plan for the storage and handling of hazardous materials (Exh. HO-ES-5). The Company indicated that it would develop these plans prior to plant operation (id.). 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 (Exhs. HO-ES-10; HO-RR-17; HO-RR-18; Tr. 6, at 63 to 76).[149]

[149] The Company's primary 24-hour response capability will be its own personnel, but it has explored the 24-hour police coverage and "on-call" fire and ambulance services available from the Town of Blackstone (Exh. HO-RR-17; Tr. 6, at 67). The Company intends to talk further about back-up support and mutual help provisions with local officials in Blackstone and Bellingham and with representatives of the several existing and proposed power facilities in the area as its emergency planning is finalized (Exh. HO-ES-10; Tr. 6, at 66 to 67).

(4) Blasting

The Company discussed the likely impacts on the proposed facilities of blasting at the adjacent Kimball sand and gravel mining operation ("Kimball") (Exhs. BLK 12.2, Section 14; HO-ES-11; HO-ES-12; HO-ES-13; HO-RR-22; HO-RR-22.1; Tr. 6, at 102 to 144; Tr. 7, at 7 to 32). The information presented by the Company included a study by the Company's consultant, ABB, conducted jointly with Kimball, covering effects of blasting on the machine foundation, power train components, representative structural components and the gas pipeline for the proposed facilities (Exhs. HO-RR-22; HO-RR-22.1). The study examined the consequences of two levels of blasting activity, the first resulting in a peak particle velocity of 0.5 inch/second at the ground by the foundation of the proposed facilities and the second resulting in the maximum legal velocity of 2.0 inch/second (Exh. HO-RR-22.1).[150]

The Company's consultant indicated that the actual seismic velocities to be expected with typical blasting activities at Kimball would be 10 times lower than the 0.5 inch/second peak particle velocity used in the study (id.). The study indicated that no fatigue effects would occur to the proposed gas pipeline under any of the conditions examined, including under blasting conditions producing peak seismic velocities of 2.0 inch/second, the legally allowed maximum (id.). The Company submitted documentation indicating that all parts of the proposed facilities would be designed to operate safely during and after a blast with a seismic impact of 0.5 inch/second maximum peak particle velocity at the ground surface on the proposed plant site location (id.).

Based on its studies, the Company stated that a 2.0 inch/second blast would cause the turbine units of the proposed facilities to trip (i.e., shut down as a safety precaution), and that certain damages would occur to the power plant equipment, but that there would be no harmful effects to the environment immediately surrounding the power plant property (id.). The

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150 The lower level of blasting activity was selected based on review of historic seismic data for blasting at Kimball from 1991 through 1994, and review of seismic reports of blasts occurring in 1996 and 1997 from GeoSonics, a company specializing in seismic recording (Exh. HO-RR-22.1, at 1).

Company indicated, however, that historically, seismic impacts of Kimball's blasting were well below the 0.5 inch/second peak particle velocity level (id.).

The Company stated that it planned a series of test blasts before initial operation of the proposed facilities to ensure that peak particle velocities of 0.5 inch/second would not threaten the integrity of facility equipment and structures (id.; Tr. 6, at 111 to 114). The Company stated that, if the planned test blasts revealed that the damping factors of the foundations for the proposed facilities were below expected values, it would enter into an agreement with Kimball that would reduce Kimball's maximum blasting levels to a level that ensured that the vibration on the equipment foundations of the proposed facilities would not exceed design levels (Exh. HO-RR-22.1; HO-RR-26(redacted); Tr. 6, at 111 to 114).

In addition, a qualified professional engineer will be engaged by the Town of Blackstone to review all seismic analyses and blasting design criteria against applicable standards, with specific attention to all safety sensitive plant components, as a condition of a special permit issued to the Company by the Town's Zoning Board of Appeals (Exh. HO-V-3.6, at 8 to 9).[151]

(5) 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

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151 Specifically, the Special Permit states that the engineer will carry out the following duties without reliance upon agreements between ANP and parties engaged in blasting unless the Town has a means of itself enforcing those agreements: (a) review the seismic analysis and design criteria prepared for the proposed facilities by the Company's engineers, and confirm that the analysis and criteria are consistent with sound engineering practice for the circumstances of the proposed project, as embodied in the provisions of the State Building Code regarding seismic design, and (b) review and confirm that actual project design will be consistent with those criteria so as to safely withstand future seismic events caused by the proximate blasting, with specific attention to all primary and secondary containment for petroleum, hazardous materials, and hazardous waste, and with specific attention to critical structural elements (Exh. HO-V-3.6, at 8 to 9).

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 be well within the IDLH standard at sensitive receptors located at or beyond the 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 normal 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 construction-related 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.

The record demonstrates, based on historical data, that Kimball's blasting has been well below the 0.5 inch/second peak particle velocity levels for which the Company has designed its proposed facilities. The record also shows that safeguards will be in place to limit the vibration on the equipment foundations of the proposed facilities to design levels. These safeguards include an anticipated agreement between the Company and Kimball to ensure that blasting impacts to the proposed facilities remain below design levels and the condition, imposed by the Town of Blackstone Zoning Board of Appeals in conjunction with a special permit, that all seismic analyses and blasting design criteria be reviewed against applicable standards, with specific attention to all safety sensitive plant components. The record further demonstrates that even blasting at the legally allowed maximum 2.0 inch/second peak particle velocity level would cause no harmful effects to the environment immediately surrounding the power plant property.

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[152]

(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 BECo, and (2) increased power flows on certain existing transmission lines (Exh. BLK-12.2, at 10-10 to 10-21).[153] The Company indicated that the proposed facility would interconnect with BECo's 345 kV 336 line, which occupies BECo's ROW 13 extending from the Sherman Road substation in Rhode Island to the West Medway substation (id. at 10-4).

The Company indicated that the maximum EMF levels from the interconnect lines, which would be located entirely on the proposed site and the adjacent 60-acre parcel in Mendon to be acquired by ANP, would be 31 milligauss ("mG") at the edge of the interconnect ROW (Exh. HO-E-1) (Section IV.D.3.a.5, below). With respect to impacts on the transmission system along ROW 13, 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

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152 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").

153 The Siting Board notes that BECo'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 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 ANP Bellingham Decision, EFSB 97-1, at 253-254; Altresco Lynn Decision, 2 DOMSB at 213; 1993 BECo Decision, 1 DOMSB at 148, 192.

flows extending south to the Sherman Road substation (Exh. BLK 12.2, at 10-21). The Company explained that, under various regional generation dispatch scenarios, the proposed project would add approximately 275 to 400 megavolt-amperes of power flow northward along the 336 line to West Medway substation (Exh. EFSB-30, at 4, Exh. RR-89S2.4).

ANP provided calculations of magnetic field levels along ROW 13 north of the interconnection point, both with and without operation of the proposed facility (Exh. BLK-12.2, at 10-18, 10-20). These calculations indicated that, under worst-case (winter peak load) conditions, operation of the proposed facility would increase maximum magnetic field levels on the eastern edge of the ROW from approximately 25 mG under base case conditions to approximately 58 mG, and on the western edge of the ROW from approximately 4 mG to approximately 9 mG for comparable conditions (id.; Tr. 2, at 119; Exhs. HO-EE-6.1; HO-EE-15.1). The Company noted that these levels would be well below the 85 mG threshold which the Siting Board has previously recognized (Companies' Brief at 44-45).

The Company indicated that, along the affected ROW segment north of the interconnection point, there are nine residences near the eastern edge of the ROW (Exhs. HO-EE-6, HO-EE-6.1). The Company stated that at the nearest residence, located 175 feet from the 336 line centerline and 90 feet from the ROW edge, the maximum magnetic field with operation of the proposed facility would be 34 mG (Exhs. HO-RR-4, HO-RR-5).

ANP also provided information from the project interconnection studies 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-V-27.4; EFSB-30). The Company stated that reconductoring of the BECo 336 line between the site and West Medway substation would be required to accommodate the full 580 MW output of the proposed project (Exh. EFSB-30, at 4).

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 (id. at 3). The Company stated that combined increases in power flows from its proposed Bellingham and

Blackstone projects would require reconductoring a 345 kV line in central Massachusetts and three 115 kV line segments in eastern Massachusetts, central Massachusetts and Rhode Island (id. at 5-10; Exh HO-V-27.4, at 23). 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,[154] the project interconnection study indicates the need to reconductor three 345 kV lines and three 115 kV line segments in eastern and central Massachusetts (Exhs. HO-EE-14.1, at 23 to 24; HO-V-27.4, at 23).

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 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. EFSB-29; EFSB-30). The 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. EFSB-29).

The Company indicated that, to accomplish the identified potential transmission upgrades, existing conductors would be replaced with larger conductors and a limited number of existing H-frame transmission structures would be rebuilt or modified (Exhs. EFSB 30; HO-V-27.4, at 17-22). The Company added that, because many of the existing H-frame transmission structures along the affected lines could support larger conductors without modification, changes to either the conductor spacing or the structure design likely would not be feasible due to cost or engineering constraints (Exh. EFSB-30). The Company indicated that the remaining design measure -- changing the phasing of adjacent circuits -- may be possible for identified upgrades which would involve lines on ROWs with multiple circuits (id.

[154] No proposal to expand the Brayton Point generating station has been filed with the Siting Board.

at 2-8).[155] The Company stated that NEPCo would be responsible for those transmission upgrades, and added that when it has signed final agreements with NEPCo, BECo and any other affected transmission providers regarding interconnection requirements and associated upgrade designs, it will provide copies of such agreements (id.; Companies' Brief at 47). The Company indicated that it would encourage affected transmission providers to incorporate prudent, cost-effective design measures that may reduce magnetic fields into any transmission upgrades required for the proposed project (Companies' Brief at 47; Exh. EFSB-30, 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 ROW 13 with operation of the proposed facility -- approximately 58 mG at the eastern edge of the ROW and 34 mG at the nearest residence -- are among the highest reviewed by the Siting Board, and also represent a substantial increase above the existing maximum level of approximately 25 mG at the edge of the ROW.

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 336 line. 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

155 Identified upgrades include: (1) the 302 line between Millbury and Carpenter Hill substations in central Massachusetts, (2) the W-175 line between Carpenter Hill and Palmer substations in central Massachusetts, and (3) a portion of the G-185 line between the Davisville tap and the West Kingston substation in Rhode Island (Exh. EFSB-30, at 5-8).

Medway substation, predominantly via key lines extending northwest to Millbury substation and beyond. A number of upgrades would 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. ANP Bellingham Decision, EFSB 97-1, at 157; Millennium Power Decision, EFSB 96-4, at 176; Silver City Decision, 3 DOMSB at 353-354.

Here, the Siting Board notes that the Company has committed to request that NEPCo, BECo 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, most 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.[156]

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[156] In addressing a similar situation in past reviews, 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. ANP Bellingham Decision, EFSB 97-1, at 158; Millennium Power Decision, EFSB 96-4, at 176-177. In ANP Bellingham, the Siting Board recognized that significant costs could be involved in modifying or replacing even a few existing transmission structures. ANP Bellingham Decision, EFSB 97-1, at (continued...)

The Siting Board notes that, as in the previous review of the ANP Bellingham facility, 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 Bellingham 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.[157]

The Company's commitment to work with 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 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 an update on the extent and design of required transmission upgrades, and the measures incorporated into the transmission upgrade designs to minimize magnetic field

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[156](...continued)
158. The Siting Board also noted, however, that to the extent transmission providers consider life cycle costs when selecting transmission upgrade designs, the cost advantage of reusing existing transmission structures, rather than rebuilding or replacing them, may not be as great as it would appear to be if only the initial installation costs were considered. Id.

[157] The Siting Board also is reviewing a proposal by IDC to construct a 700 MW (reduced from 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.

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 336 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 Blackstone 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 Blackstone and the region (Exh. BLK-1, at 6-61). The Company further asserted that the proposed project would be compatible with surrounding uses and would provide economic benefits to the region during both construction and operation of the facility (id. at 6-62, 6-64).

The Company expects to acquire an additional 60 acres of land in Mendon, which abuts the northern boundary of the proposed site, and which would be traversed by the proposed gas and electric interconnect lines where they extend beyond the present site boundary (Exhs. BLK-BEC-14, at 5-9, 5-10; EFSB 98-2, Tr. 1, at 78).

The Company stated that the proposed facility is to be constructed on approximately 31.6 acres of a 158 acre site which is located generally northeast of Elm Street between Bellingham Road and Blackstone Street in the Town of Blackstone (Exh. BLK-1, at 6-61). The Company stated that the proposed site is located in a residential-3 ("R-3") zone (id.). The Company explained that its proposed project is an allowed use under this category of zoning but that special permit review by the Blackstone Zoning Board of Appeals ("ZBA") would be required to ensure that appropriate design standards would be met (Exh. BLK-1 at 6-62; Tr. 5, at 68-71).

The Company indicated that the 158 acre site is currently vacant and is generally wooded except in the southern portion where the land previously had been disturbed as a result of sand and gravel mining operations at the existing Kimball Sand and Gravel facility that immediately abuts the proposed site to the south (id., 6-59; HO-EL-10). The Company described the southern portion of the proposed site as being generally level and clear of trees and indicated that that portion of the site would contain the main structures of the proposed facility (Exh. BLK-1 at 6-61, Figs. 1.4-2, 6.5-1, 6.5-2). The abutting land to be acquired in Mendon is generally wooded, but is traversed or bounded by electric, gas and telephone utility easements (cite).

The Company indicated that level portions of the site adjacent to the project footprint area, as well as Kimball-owned property in the vicinity of the proposed facility access drive would be used to facilitate construction activity and to provide space for construction parking and materials laydown areas[158] (Exh. HO-RR-14; Tr. 5, at 54-56).

The Company described the land uses contiguous with the proposed site as the aforementioned Kimball Sand and Gravel operation immediately to the south, and a residential neighborhood along Pudding Stone Lane in Mendon immediately to the north (Exh. BLK-1, at 6-61 to 6-62, Fig 6.5-2) . The Company stated that to the west, woodlands, wetlands and a pond associated with the Mill River provide buffering between the project site and existing residential uses that are located along Spruce Street and Laurel Road in Blackstone (id.). To the east, the proposed site is bordered by densely wooded vacant land that is owned largely by the Kimball Sand Company (id.; Exh. BLK-12.2, at Fig. 11-7). Further to the east are several residential lots which front along Bellingham Road (id.).

[158] The Company also indicated that on-site lands originally identified as the location for two oil storage tanks -- these tanks are no longer proposed as ANP does not plan to use oil as a backup fuel -- potentially would provide additional on-site space for construction related activity (Exh. HO-RR-14; Tr. 5, at 54-56).

Based on 1991 land use data available from the Massachusetts Geographic Information System Office ("MassGIS"), the Company estimated that 75 percent of the area within a one-mile radius of the proposed site is forest, open or agricultural land, 18 percent is devoted to residential uses, and 7 percent is used for commercial or industrial purposes (Exh. HO-EL-3.2). Within a half-mile radius of the proposed site, the Company estimated that 73 percent of the land is forest, open or agricultural, 13 percent is residential, and 14 percent is used for industrial or commercial purposes (id.).[159]

The Company stated that its proposed facility would be buffered from nearby residential uses by distance and natural features, including wetlands, as well as by surrounding developed uses including the Kimball facility. Furthermore, the Company indicated that, pursuant to an agreement with the Town of Blackstone, it would convey to the town approximately 125 undeveloped acres of the 158 acre site that would then be preserved and maintained by the Town as conservation land accessible to the public (Exhs. HO-EL-15; Tr. 5, at 57)[160].

The Company indicated that the majority of residential uses in the vicinity of the site are located along Pudding Stone Lane in Mendon and on Spruce Street and Laurel Road in Blackstone (Exh. BLK- 1, at 6-61, 6-62). The Company stated that presently, the closest residence to the proposed facility is located on Pudding Stone Lane approximately 1339 feet to the north of the closest facility structure, a water storage tank (Exh. HO-EL-1.1 (Revised); Tr. 5, at 41). The Company stated that a mature vegetative buffer exists between the proposed

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159 The Company asserted that it used various ground-truthing techniques to confirm the validity of the MassGIS data for 1998 conditions (Exh HO-EL-17; Tr. 5, at 29-30). The Company also stated that an aerial photograph from 1995 was used in combination with verification by field personnel to identify and account for any significant changes with respect to existing land uses (Exh. BLK-1, at 6.5-1; Tr. 5, at 29-31).

160 The Company explained that fee ownership of the acreage not occupied by the power plant would be transferred to the Town of Blackstone, and that its designation as conservation land would effectively preserve buffers between the proposed facility site and existing residential uses (Tr. 5, at 37, 57).

facility and residences along Pudding Stone Lane, and provided assurances that none of the existing buffer would be removed by construction of the proposed project (Tr. 5, at 40). The Company stated that significant vegetative buffer, encompassing the Mill River and associated wetlands, lies between the facility site and residential uses to the west of the site along Spruce Street and Laurel Road (id.).

The Company noted that it developed two Property Compensation Programs to mitigate potential impacts to residential property values for residents within .64 miles of the project footprint (Tr. 5 at 61-65). The Company indicated that it developed these programs to address the property value concerns of area residents and compensate for other potential environmental impacts of the project, including noise and visual impacts (id.; Company Brief at 173).

The Company stated that it identified a total of 119 residences within one half mile of the proposed facility, and that it identified 322 residences located within one mile of the project (Exh. HO-EL-2; HO-EL-16).[161] The Company indicated that the nearest undeveloped land potentially available for residential development would be the Kimball-owned properties that lie immediately to the west, south, and east of the site boundary (Exh. HO-EL-4). The Company asserted that while these lands are zoned residential, they currently support an active portion of the Kimball Sand Company's operations.[162] The Company explained that the project property line was drawn close to the proposed facility footprint in these areas to allow continued sand and gravel activity on lands immediately adjacent to the proposed facility (Exh. HO-EL-4). The Company also stated its intention to reach an agreement with the land owner that would place noise encumbrances on future residential development in these same areas (id.; Exhs. HO-RR-35; Tr. 7, at 170). Therefore, the Company asserted that the closest land

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[161] The Company stated that it identified the areas located within one-half and one mile of the proposed facility by describing those areas that would be within one-half and one mile of the site boundary rather than by defining a circle with its radius originating from a central point within the project footprint (Exh. HO-EL-3.1).

[162] The Company noted that a portion of the Kimball property is zoned industrial, but indicated that sand and gravel mining operations are not confined to the industrial zone (Exh. BLK-1 at 6-62, and Figs. 6.5-1, 6.5-3).

reasonably available for future residential development would be further to the east of the site behind existing residences located along the west side of Bellingham Road more than 1200 feet from the project footprint (Exhs. HO-EL-4, Company Brief at 179).

The Company also considered the possibility that residential development could occur to the west of facility site on the west side of the Mill River on the Higgins/Blake parcel (Exhs. BLK 12.2, at Fig 11-7; HO-RR-28; Tr. 7, at 86-94). The Company asserted that any residential development on that parcel would be to the west of the riverfront area and wetlands protection zone, at a distance of at least 1200 feet from the closest facility structure (Exh. HO-RR-28; HO-RR-28.1).

The Company stated that the proposed site is located within a residential zone, and that its proposed facility is a permitted use under this zoning category (Exh. BLK-1, at 6-2). The Company indicated that in order to comply with all Town of Blackstone zoning restrictions, it had secured special permits from the ZBA and the Blackstone Planning Board relative to two issues: (1) the classification of the project as a "public utility" and therefore as an allowed use within an R-3 zone[163], and (2) a waiver of applicable zoning by-laws relating to the location of the proposed facility within the Town's groundwater protection district, as it is currently delineated[164] (Exhs. BLK-1, at 6-62; HO-EL-9; Company Brief at 177-178).

With respect to impacts on 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 or its interconnects

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163 The Company stated that the special permit review also encompassed a general review of the project to ensure consistency with the design standards of the Town (Exhs. BLK-1, at 6-62; Company Brief at 177-178).

164 The Company stated that the boundaries of the groundwater protection district likely will be redrawn consistent with MDEP criteria, and that the project footprint would then fall outside of GWPD boundary (Exh. HO-EL-9; Tr. 5, at 14-20).

(Exh. BLK-1, at 6-56). The Company also stated that there were no known rare plants, animals, or exemplary communities in the project area (id.; and Exh. HO-EL-14.3).

The Company indicated that the footprint of the generating facility would require no tree clearing, but that the gas and electric interconnnects would require clearing of 25.6 acres (Exh. HO-RR-J8).

The Company asserted that, after construction is completed, it would reclaim and landscape certain cleared portions of the proposed site, including previously disturbed and unvegetated areas to the northeast, north and northwest of the facility, as well as the southerly portion of the facility site adjacent to the access road (Exhs. BLK-1, at 6-57; HO-EL-10; BLK 12.2, at Figs. 7-13, 7-14; Tr. 5, at 39-40). The Company asserted that its proposed landscaping would offset, in part, the clearing of trees for the gas and electric interconnects. The Company also stated that its on-site landscaping plan, which includes the planting of trees, grasses and shrubs in previously disturbed areas, could result in net improvements to the terrestrial habitat characteristics of the site in the vicinity of the project footprint (Exh. BLK-1, at 6-57).

The Company indicated that an initial survey for historic and archaeological resources found the proposed site to be of low sensitivity with respect to such resources (Exh. BLK-1, at 6-67). The Company stated that no significant historical or cultural resources are likely to remain at the proposed site due to the high degree of disturbance resulting from sand and gravel operations in the area (id.). The Company noted that the gas supply and electric interconnects traversed lands having greater potential for cultural resources but that surveys have been completed in these areas, and no significant cultural resources meriting further investigation were identified (Tr. 1, at 6; Exh. BLK-BEC-16).

Finally, the Company stated that because water and sewer interconnects for the proposed facility would be co-located with the proposed project access driveway, which will traverse a previously disturbed portion of the Kimball property[165], no permanent land use

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[165] The Company stated that the project access road would branch off from the existing (continued…)

impacts would result from the construction of those facilities (Exh. HO-EL-9; Tr. 5, at 11-14).

(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 residential use, but 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 27 percent being used for residential or commercial purposes.

The proposed facility is an allowed use under the zoning by-laws of the Town of Blackstone. The Siting Board notes that while the proposed stacks and other facility structures would be considerably taller than existing structures in the area, the project proponent has received from the Blackstone ZBA the two Special Permits needed to construct the facility with building heights and other characteristics as currently proposed.

Although construction of the project interconnect lines would require clearing 25.6 acres of trees, the Company intends to implement a landscaping plan that would reclaim previously disturbed areas of the proposed site that lie outside of the facility footprint area. The Company also would convey sizable portions of the 158-acre site in Blackstone, and the abutting 60-acre area in Mendon, to the respective towns for conservation purposes.

The Company has adequately considered the impacts of the proposed facility with respect to wildlife species and habitats, and historic and archaeological resources.[166]

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[165](...continued)
Kimball driveway and would be located within an approximately 50 foot wide easement that would be negotiated between ANP and Kimball (Tr. 5, at 9-10).

[166] 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

(continued...)

Moreover, the Siting Board notes that the proposed project will undergo additional reviews by other state and local authorities with respect to these issues.

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 year 2000 dollars (Exh. HO-C-1). The Company stated that this cost estimate reflects current site-specific estimates of: (1) construction costs; (2) electric transmission line and gas pipeline interconnect costs; (3) a contingency allowance;[167] (4) site acquisition costs; and (5) licensing and development costs (id.; Tr. 4, at 30). 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 181).

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

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(...continued)
proposed gas pipeline was ongoing.

[167] The Company indicated the contingency allowance covers CO_2 mitigation and the total capital costs include NO_x offset costs (Exh. EFSB-71, at 4-6).

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. EFSB-55). 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-21). 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 (Exhs. EFSB-48, at 3-36 to 3-37; EFSB-71, 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 \$7.4 million to limit the noise increase over the L_{90} to 7dBA at the closest residential receptor, and (2) an additional \$1.8 million to limit the noise increase over the L_{90} to 9 dBA at the Mendon Town line (Exhs. HO-RR-52.1; EN-14.1: Tr. 7, at 99).

The record contains estimates of the overall costs of the proposed facility at the proposed site, as well as information on relative costs for measures to further minimize environmental impacts.

Accordingly, the Siting Board finds that the Company has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

Based on our review of the entire record in this case, the Siting Board finds that the project proponent has provided sufficient information regarding environmental impacts and potential mitigation measures to allow us to determine if the appropriate balance among environmental impacts and between environmental impacts and cost has been achieved.

4. Conclusions on the Proposed Generating Facility

In this section, the Siting Board reviews the consistency of the proposed facility with its overall review standard, which requires that the appropriate balance be achieved between environmental impacts and costs. Such balancing includes trade-offs among various environmental impacts as well as between these environmental impacts and costs.

The Siting Board has found that, with the implementation of the conditions specified in Section III.B.2 above, the environmental impacts of the proposed facility at the primary site would be minimized with respect to air quality, water supply, water-related discharges, construction related impacts to wetlands, visual impacts, traffic, safety, EMF, and land use. Further, in Section III.B.3, the Siting Board has found that ANP has provided sufficient information on the costs of the proposed facility to allow the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts and cost.

The record indicates that there are no significant issues involving the balance among water-related discharges, construction related impacts to wetlands, traffic, safety, EMF, and land use, nor between any of these concerns and cost.

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 Section 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 the 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. ANALYSIS OF THE PROPOSED TRANSMISSION FACILITIES

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 reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.[168] In carrying out this statutory mandate with respect to proposals to construct facilities that are not generating facilities, the Siting Board evaluates whether there is a need for additional energy resources[169] 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. Boston Edison Company, EFSB 96-1, 8-9 (1997).

Here, the Siting Board is presented with a proposal to construct a jurisdictional transmission line that would connect a new supply source, specifically a generating plant, to the regional transmission system. In cases such as this, the proponent first must establish that the power generating facility will contribute to a reliable supply of energy for the Commonwealth with a minimum impact on the environment at the lowest possible cost. If it can be established that the plant so contributes, the proponent then must show that the existing transmission system is inadequate to support this new supply source and that additional energy resources are necessary to accommodate the new supply source. Massachusetts Electric Company/New England Power Company, 18 DOMSC at 383, 395; Turners Falls Limited Partnership, 18 DOMSC at 141 (1988) ("Turners Falls").

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168 As amended by St. 1997, c. 164, § 204.

169 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").

2. Need for the Proposed Transmission Lines

In Section II.A.5, above, the Siting Board has found that the proposed generating facility in Blackstone is needed for reliability, economic efficiency, and environmental purposes. The proposed plant would be capable of providing a nominal 580 MW of power to the area 345 kV transmission system (Exh. BLK-BEC-14, at 1-1, Fig. 1-4). Consequently, the Siting Board finds that the proposed generating facility will contribute to a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In order to deliver the nominal plant output of 580 MW to the area 345 kV transmission system, the Companies propose to construct two 1.1-mile overhead transmission lines in a loop design (Exh. BLK-BEC-14, at 1-1; Tr.-J-1, at 77). The proposed lines would interconnect the proposed generating facility to BECo's Line 336 on its ROW 13 in Mendon (Exh. BLK-BEC-14, at 1-1, Fig. 1-4). The Companies indicated that Line 336 is the nearest transmission line to the proposed generating facility and is located approximately one-half mile northwest of the proposed site at its nearest point (id.).

The Companies stated that an electric interconnection is required for the proposed ANP Blackstone project to supply power to Massachusetts and New England (id. at 2-2). The Companies further stated that, consistent with federal initiatives relating to deregulation of the power generation industry, owners of transmission facilities, such as BECo, are required to provide independent power plant developers, such as ANP, access to the transmission system to enable the power plant output to be sold into the regional power market (id. at 2-1).

As discussed above, the Companies have proposed transmission line facilities based on the need for the proposed ANP Blackstone generating facility filed in EFSB 97-2. The Siting Board notes that the proposed generating facility cannot supply energy to the region in the absence of an adequate and reliable energy facility to interconnect the plant to the transmission system. The record indicates that such a facility does not currently exist, and that the nearest existing transmission line is approximately one-half mile from the proposed generating facility.

The Siting Board therefore finds that the Companies have established that the existing transmission system is inadequate to support the proposed generating facility.

Accordingly, the Siting Board finds that the Companies have established that there is a need for additional energy resources to interconnect the proposed generating facility with the regional transmission system.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, § 69H[170] requires the Siting Board to evaluate proposed projects in terms of their consistency with providing a reliable energy supply to 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; (b) other sources of electric power or natural gas; and (c) no additional electric power or natural gas.[171,172]

In implementing its statutory mandate, the Siting Board requires a petitioner to show that, on balance, the proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the identified need. 1998 NEPCo Decision, EFSB 97-3, at 20; 1997 BECo Decision, EFSB 96-1, at 37; 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. 1998 NEPCo Decision, EFSB 97-3, at 20-25; 1997 BECo Decision, EFSB 96-1, at 38-42; Massachusetts Electric Company, 18 DOMSC at 383, 404-405 (1989).

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170 As amended by St. 1997, c. 164, § 204.

171 G.L. c. 164, § 69J, as amended, 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 IV.C, below.

172 G.L. c. 164, § 69J, as amended by St. 1997, c. 164, § 209.

2. Identification of Project Approaches for Analysis

The Companies considered four alternative approaches for meeting the identified need to interconnect the ANP Blackstone generating facility with the area 345 kV transmission system (Exh. BLK-BEC-14, at 3-2 to 3-3).[173] The Companies identified three transmission alternatives -- the proposed loop configuration, a double radial alternative, and a single radial alternative (id.). The Companies also identified a low-voltage alternative (id.).

a. The Proposed Loop Configuration

The proposed loop configuration ("loop configuration") would connect the proposed generating facility to the area 345 kV transmission system in Mendon via two new 1.1-mile overhead transmission lines and an associated 345 kV transmission substation within the plant footprint (Exh. BLK-BEC-14, at 1-3, 3-2; Tr.-J-1, at 77). The Companies stated that the loop configuration would break the existing BECo Line 336 at the tap point -- thus creating a north and south segment -- and reroute both segments into the new transmission substation at the site of the proposed generating facility (Exh. BLK-BEC-14, at 3-2). Thus, the loop lines would carry the entire load flowing along BECo's Line 336, plus the output of the proposed generating facility (id.). Based on the selected primary route, the Companies indicated that the loop configuration would extend from ANP's proposed switchyard in Blackstone in a generally northeasterly direction through woodland, cross the Mendon town line, and then proceed northwesterly to BECo ROW 13 (Exh. BLK-BEC-11). The Companies stated that the loop

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173 The Companies stated that they also considered a no build alternative (Exh. BLK-BEC-14, at 3-3). The Companies explained that under the no build alternative, the proposed 580 MW ANP power plant in Blackstone would be unable to interconnect to the regional transmission system (id.). The Siting Board notes that the no build alternative would not meet the identified need, and therefore eliminates it from further consideration.

configuration would cost $10.5 million, and would be capable of carrying 1,780 MVA[174] of load under normal operating conditions (Exhs. BLK-BEC-14, at 4-21, 5-20; HO-J-N-2).

b. Double Radial Alternative

The double radial alternative would connect the plant output to the regional transmission system via two new overhead transmission lines extending from the plant substation out to a second new substation located on BECo's ROW 13 (Exh. BLK-BEC-14, at 3-2, 4-3).[175] The Companies explained that the double radial lines would carry only the plant output power levels, and that consequently the plant substation would be smaller than that required under the proposed loop configuration (id. at 4-3). The Companies indicated that the double radial alternative, if located above ground, would cost $12.9 million (id. at 4-21).

c. Single Radial Alternative

The Companies identified two variations of a single radial alternative, each of which involved the construction of a single 345 kV line between the plant substation and BECo's Line 336 (Exhs. BLK-BEC-14, at 3-2; HO-J-R-1). The Companies stated that the first alternative would connect the new single line directly with Line 336; the second alternative would connect the new single line to BECo Line 336 at a new substation constructed within BECo's ROW (id.). The Companies stated that the first single radial alternative would present an

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174 The Companies indicated that the capacity of the loop configuration would be larger than the present 1,255 MVA normal rating and 1,400 MVA emergency rating of the existing Line 336 by 525 MVA and 900 MVA, respectively (Exh. HO-J-N-2). The Companies further indicated that under a wide range of dispatch and load scenarios, the normal rating of Line 336 is not projected to be exceeded in the near future (Exh. HO-J-N-2.1).

175 The Companies indicated that the support structures and line configurations associated with the double radial alternative would be virtually identical to those used with the loop configuration, e.g. parallel sets of support structures to accommodate both lines (Exh. HO-J-E-2).

unacceptable risk to the regional transmission system (Exh. BLK-BEC-14, at 3-2).[176] The Companies indicated that the second single radial alternative would preserve the reliable operation of the regional transmission system, and would require a narrower ROW and fewer associated transmission support structures than the loop configuration or the double radial alternative (id.). However, the Companies stated that because the entire output of the proposed generating facility would be carried by a single radial line, the generating facility's operation would be vulnerable to a single failure along the interconnect line, thus violating ANP's reliability criteria (Exh. BLK-BEC-14, at 3-2). The Companies also stated that maintenance restrictions would be a disadvantage of the single radial alternative (Exh. HO-J-R-1, at 2). The Companies noted that the second single radial alternative would have no cost advantage over the loop configuration, because a second substation would be required at ROW 13 and the additional costs of that substation would more than offset the cost savings associated with using just one transmission line and associated support structures (Exh. BLK-BEC-14, at 3-2).

d. Low-Voltage Alternative

The low voltage alternative would deliver power, at the proposed plant's 21 kV generator output voltage, along new interconnecting lines to a new voltage step-up substation on ROW 13 (Exh. BLK-BEC-14, at 3-2 to 3-3). The Companies asserted that the low-voltage alternative is not a reasonable approach to connecting the proposed plant to the regional transmission system (id.). The Companies noted that the low-voltage alternative would require a large number of lines carrying a higher current to convey the full plant output to the regional transmission system (id.). If placed above-ground, this alternative would require multiple pole

176 The Companies explained that a direct connection would create a fourth terminal on Line 336 and that a transmission line with more than three terminals cannot be protected (Exh. BLK-BEC-14, at 3-2 to 3-5). The Companies stated that, without a substation on the ROW, Line 336 would shut down all four terminals whenever a fault occurred at any terminal or on the line itself (id.). The Companies added that this condition is not acceptable to either BECo or ANP, and that it could impair reliability of service to the public (id.).

lines to support heavy, multiple bundled conductors (id.).[177] In addition, the Companies noted that the higher currents would generate magnetic fields along the route that would be sufficiently strong to cause radio and television interference in the vicinity of the circuits (id. at 3-3; Exh. HO-J-E-6). Further, the Companies stated that the low-voltage alternative would require a substantially larger substation at ROW 13 in order to accommodate step-up transformers (Exh. BLK-BEC-14, at 3-3). The Companies stated that they eliminated the low-voltage alternative from further consideration because of the generic capacity limitations on low-voltage circuits, the necessary facility configurations, and the resultant environmental impacts (id. at 3-5).

e. Analysis

The Companies have identified four distinct project approaches, of which two -- the proposed interconnect and the double radial alternative -- could both maintain the reliability of BECo's Line 336 and provide reliable service for the proposed 580 MW generating plant. The Siting Board agrees with the Companies' conclusion that the first single radial alternative and the low-voltage alternative do not warrant further evaluation based on their poor reliability or environmental disadvantages, and their lack of offsetting cost or other advantage over the loop configuration and the double radial alternative. The Siting Board also accepts the argument that the second single radial configuration is unacceptable due both to the vulnerability of the plant output to a line failure, and maintenance restrictions. Therefore, the Siting Board focuses on the two remaining 345 kV interconnect configurations -- the loop configuration and the double radial alternative.

The Siting Board finds that both the loop configuration and the double radial alternative would meet the identified need. In the following sections, the Siting Board compares the loop

[177] The Companies stated that, if sited underground, a greater number of conductors would be needed, and added that the heat generated within an underground duct enclosing the conductors would be extremely problematic (Exh. BLK-BEC-14, at 3-3).

configuration and the double radial alternative with respect to reliability, environmental impacts, and cost.

3. Reliability

The Companies stated that both the loop configuration and the double radial alternative could meet the identified need while maintaining system reliability (Exhs. BLK-BEC-14, at 3-4; HO-J-R-1). The Companies asserted that the double radial design was slightly more susceptible than the loop configuration to a single fault, because the double radial design requires two substations, thus increasing exposure to equipment failure (Exh. HO-J-R-2, at 2). However, the Companies added that because both the loop design and double radial design incorporate redundant facilities, e.g., two transmission lines and associated switchgear, the reliability of both designs would be essentially equivalent (id.).

The record demonstrates that either the loop configuration or the double radial alternative would provide two individual paths by which the proposed generating plant's entire output could be coupled to the area 345 kV transmission system. Accordingly, the Siting Board finds that the loop configuration would be comparable to the double radial alternative with respect to reliability.

4. Environmental Impacts

In this Section, the Siting Board compares the loop configuration to the double radial alternative with respect to environmental impacts resulting from: (1) facility construction; (2) permanent land use; and (3) magnetic field levels.

a. Facility Construction Impacts

The Companies asserted that, given the proposed siting along a route removed from residences and built-up areas, either the loop configuration or the double radial alternative would have minimal construction impacts to the surrounding community (Exh. HO-J-E-2). However, the Companies stated that the double radial alternative would have greater construction impacts because it requires the construction of a substation on BECo ROW 13, in addition to the substation at the generating facility site (id.).

The Companies noted that, for either alternative, transmission line construction would take approximately four months and would require access to the route from the plant site in Blackstone and from Bates Road in Mendon (id.). However, the Companies noted that construction of the ROW substation required by the double radial alternative would take between 12 and 15 months; thus, the double radial alternative would require construction access from Bates Road for a longer period than would the loop configuration (id.).

The record indicates that the double radial alternative would require the construction of a substation on BECo's ROW, and that such construction would have the effect of prolonging the need for construction vehicle access from Bates Road in Mendon. Accordingly, the Siting Board finds that the loop configuration would be preferable to the double radial alternative with respect to facility construction impacts.

b. Permanent Land Use Impacts

The Companies asserted that the land use impacts of the proposed loop configuration would be somewhat less than those of the double-radial alternative, due primarily to the need for a second substation and an associated access road under the double-radial alternative (Exh. HO-J-E-2, at 1-2). The Companies also noted that aggregate tree clearing required for the loop configuration would be approximately 1.1 acres less than that required for the double radial alternative. The Companies indicated that the second substation required for the double-radial alternative would represent an incremental visual impact at ROW 13 not present under the loop configuration (Exh. HO-J-E-2, at 5).

The Companies stated that there would be no direct wetland impacts under either the loop configuration or double radial alternative (Exh. HO-J-E-2, at 1-2). Further, although construction of the transmission lines would occur within buffer zone areas, impacts would be temporary and would be the same under either design (id. at 2-3).

The record indicates that the loop configuration would have slightly lower tree clearing and visual impacts than would the double radial alternative, due to the need of the double radial alternative for a second substation outside the site of the generating facility. The visual impacts of either interconnect design would, to a large degree, be naturally mitigated by the proposed route which runs through primarily wooded and non-populated land.

Accordingly, the Siting Board finds that the loop configuration would be preferable to the double radial alternative with respect to permanent land use impacts.

c. Magnetic Field Impacts

The Companies compared the calculated maximum magnetic field levels for the loop configuration and double radial alternative as they would occur both within the ROW and at both ROW edges (Exh. HO-J-E-1). The Companies indicated that within the ROW, the loop configuration would produce magnetic field levels of up to 315 mG, as compared to 140 mG under the double radial alternative (id. at 2). The Companies indicated that magnetic fields at the western and eastern ROW edges under the loop configuration would be 31 mG and 28 mG, respectively, as compared to 17 mG and 6 mG under the double-radial alternative (id.). The Companies' witness, Dr. Bailey, testified that under either design, there would be no measurable increase in EMF levels at nearby residences due to their distance from the proposed route (Tr.-J-2, at 107-109).

The record indicates that magnetic field levels associated with the loop configuration would be higher than those associated with the double-radial alternative, both on the ROW and at the western and eastern ROW edges. However, the distance from the proposed ROW to the nearest residences likely precludes magnetic field impacts on populated areas, regardless of the choice of configuration.

Consequently, the Siting Board finds that the loop configuration would be comparable to the double radial alternative with respect to magnetic field levels.

d. Conclusions on Environmental Impacts

In Sections IV.B.4.a, b, and c, above, the Siting Board has found that: (1) the loop configuration would be preferable to the double radial alternative with respect to facility construction impacts; (2) the loop configuration would be preferable to the double radial alternative with respect to permanent land use impacts; and (3) the loop configuration would be comparable to the double radial alternative with respect to magnetic field levels. Consequently, the Siting Board finds that the loop configuration would be preferable to the double radial alternative with respect to environmental impacts.

5. Cost

The Companies estimated that the total capital cost of the loop configuration would be $10.5 million, while that of the double radial alternative would be $12.9 million (Exh. BLK-BEC-14, at 4-21, 5-20). The Companies also indicated that operating and maintenance costs would be higher for the double radial alternative than for the loop configuration, due primarily to the need for periodic maintenance at the second substation; however, the Companies did not quantify this cost difference (id. at 3-2; Exhs. HO-J-N-4; HO-J-N-5). Finally, the Companies stated that line losses would be somewhat higher for the loop configuration than for the double radial design (Exhs. HO-J-N-4; HO-J-N-5).[178]

The record demonstrates that the capital cost of the loop configuration would be $10.5 million, or $2.4 million less than the capital cost of the double radial alternative. With respect to ongoing costs, the record indicates that there would be additional maintenance costs associated with the double radial alternative's second substation, and incremental line losses

[178] The Companies indicated that line losses under the loop configuration would range from 50 to 92 kW-hours ("kWh") per hour of plant operation, while losses under the double radial alternative would range from 28 kWh to 34 kwh per hour of plant operation (Exhs. HO-J-N-4; HO-J-N-5). The Siting Board notes that at a theoretical $.03/kWh cost, the incremental line losses associated with use of the loop configuration would be valued at approximately $10,500 annually. This estimate is based on an average power loss difference between the two design configurations at 40 kWh per hour of plant operation, 24 hours a day, 365 days per year.

associated with the loop configuration. These operating and maintenance costs and line loss costs have not been quantified. However, it seems clear that the line loss costs would be significantly less than the $2.4 million difference in capital costs (See n. 177, above.)

Accordingly, the Siting Board finds that the loop configuration would be preferable to the double radial alternative with respect to cost.

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

In comparing the loop configuration to the double radial alternative, the Siting Board has found that both the proposed interconnect and the double radial alternative would meet the identified need.

The Siting Board has also found that the loop configuration would be comparable to the double radial alternative with respect to reliability, and preferable to the double radial alternative with respect to environmental impacts and cost. Accordingly, the Siting Board finds that the loop configuration is preferable to the double radial alternative with respect to providing a necessary energy supply for the Commonwealth, with the least environmental impacts, and at the lowest possible cost.

C. Site Selection

1. Standard of Review

The Siting Board has a statutory mandate to implement the policies of G.L. c. 164, §§ 69H-69Q to provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, §§ 69H and J.[179] 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

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[179] As amended by St. 1997, c.164, §§ 204 and 209.

while ensuring supply reliability. 1998 NEPCo Decision, EFSB 97-3, at 34; 1997 BECo Decision, EFSB 96-1, at 57; 1991 NEPCo Decision, 21 DOMSC at 376.

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. 1998 NEPCo Decision, EFSB 97-3, at 36; 1997 BECo Decision, EFSB 96-1, at 59; NEA Decision, 16 DOMSC 335, 381, 409 (1987). In order to determine that a facility proponent has considered a reasonable range of practical alternatives, the Siting Board requires the proponent to meet a two-pronged test. First, the facility proponent must establish that it developed and applied a reasonable set of criteria for identifying and evaluating alternatives in a manner which ensures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposal. 1998 NEPCo Decision, EFSB 97-3, at 36; 1997 BECo Decision, EFSB 96-1, at 59; 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 Companies' site selection process, including their development and application of siting criteria, as part of their site selection process.

2. Development and Application of Siting Criteria

a. Description

ANP and BECo stated that the proposed ANP Blackstone facility site was selected based on its proximity to available transmission systems (Exh. BLK-BEC-14, at 4-1). The Companies stated that they determined that the interconnection should be made with BECo's 345 kV Line 336 via a new substation,[180] and indicated that, due to the proximity of Line 336

[180] ANP and BECo noted that the next closest high-voltage transmission line is NEPCo's (continued...)

to the proposed ANP Blackstone facility site, the range of reasonable siting alternatives for transmission interconnection facilities was necessarily limited (id. at 4-2, 4-3).[181]

As discussed in Section IV.B above, ANP and BECo considered two possible interconnection configurations -- a loop configuration and a double radial tap alternative (Exh. BLK-BEC-14, at 1-6). The loop configuration involved breaking Line 336 into northern and southern segments and extending the segments to a substation at the ANP Blackstone facility, while the double radial tap alternative involved siting substation facilities at the point of interconnection with the existing Line 336 and extending tap lines from the new substation to the ANP Blackstone facility (id.).

ANP and BECo stated that they developed and applied two sets of criteria as part of their route selection process: (1) a set of threshold criteria, which were used to identify possible route configurations; and (2) a set of detailed screening criteria, which were used to rank the identified options (id. at 4-2).

ANP and BECo developed threshold criteria that addressed four sets of issues: substation location, interconnection location, transmission corridor guidelines, and protected resources (id. at 4-4 through 4-6). With respect to substation location, the criteria provided that a substation could be located either within the fence line of the proposed power plant, or adjacent to the existing BECo right-of-way, but not at intermediate points (id. at 4-4 to 4-5).

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[180](...continued)
303 Line, which runs between the West Medway Substation and the Brayton Point Substation (Exh. BLK-BEC-14, at 3-1). At its closest point, Line 303 is approximately four miles away from the proposed project site (id.).

[181] In its initial power plant petition, ANP Blackstone anticipated using a non-jurisdictional interconnection similar to the Spruce Street Underground Radial, but in an underground loop configuration (Exh. BLK-BEC-14, at 1-1, 1-2, 1-10; Tr.-J-1, at 9; Companies' Brief at 5). However, upon consultation with BECo, the underground loop configuration was deemed to be an unacceptable transmission option according to BECo's standards (Tr.-J-1, at 9 to 12). ANP also stated that discussions with the Town of Mendon led it to conclude that an alternative route more acceptable to both Blackstone and Mendon could be found (Tr.-J-1, at 52).

In addition, the substation could not be located within mapped/delineated wetland resource areas (id. at 4-5). With respect to the interconnection location, the Companies required that the interconnection points be within a mile of the proposed power plant fence line (id.).[182] The Companies developed six distinct transmission corridor guidelines: (1) overhead routes are to be evaluated assuming the ability to use either radial or loop configurations, while underground routes are to be evaluated assuming the ability to use only a loop configuration; (2) transmission routes must be located within or immediately adjacent to existing utility or transportation corridors for at least 50 percent of their off-site length; (3) overhead transmission routes require a corridor 300 feet wide; (4) overhead transmission corridor boundaries may not be located within 100 feet of a residential structure; (5) underground transmission lines may not be within approximately 50 feet of a residential structure; and (6) all routes that cross the Mill River and associated wetlands must be designed so as to avoid clearing of vegetation within wetlands or the 200-feet riverfront zone (id. at 4-6). Finally, with respect to protected resources, the threshold criteria prohibited location of either the interconnection or the substation within or abutting a known NHESP habitat, outstanding resource water ("ORW"), area of critical environmental concern ("ACEC"), protected wetlands or a certified vernal pool, or within other protected land (id.).

ANP and BECo indicated that application of the threshold criteria resulted in the identification of six configuration/routing alternatives -- the Elm Street Underground Radial; the Spruce Street Underground Radial; the Pine Needle Drive Underground Radial; the Mendon Northeast Overhead Loop ("Mendon Overhead Loop"); the Mendon Northeast

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[182] ANP and BECo stated that the 1.0 mile radius would have been reconsidered if a geographically diverse set of routes were not identified within that radius (Exh. BLK-BEC-14, at 4-5). However, the Companies indicated that the process did identify such a set of routes (id.).

Overhead Radial ("Mendon Overhead Radial"); and the Mendon Northeast Underground Radial ("Mendon Underground Radial") (id. at 4-6 through 4-13).[183]

ANP and BECo explained that their screening criteria were designed to determine which routes would minimize community impacts, natural resource impacts, and cost, while maintaining the reliability of the interconnection (id. at 4-13).[184] The Companies developed three categories of screening criteria: (1) community impact; (2) natural resource impact; and (3) cost (id.). The community impact criteria included: (1) proximity to sensitive receptors; (2) visual impacts; (3) construction impacts on traffic; (4) construction impacts on residences; and (5) impact of off-site operations (id. at 4-15 to 4-17). The natural resource criteria included: (1) wetland/floodplains; (2) tree clearing[185] (3) surface waters; and (4) groundwater

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[183] The Spruce Street Underground Radial and the Elm Street Underground Radial interconnect with Line 336 at the same point, but travel in different directions to the facility site (Exh. BLK-BEC-14 at Figure 4-3). The four remaining routes, the Mendon Overhead Loop, the Mendon Overhead Radial, the Mendon Underground Radial, and the Pine Needle Drive Underground Radial also have a common interconnection point, and are all located to the north and northeast of the proposed ANP Blackstone power plant (id.). The route for the Mendon Overhead Loop and the Mendon Overhead Radial are identical (id.). The Mendon Underground Radial follows in part the route of the Mendon Overhead Loop and Mendon Overhead Radial, but deviates for approximately 50 percent, extending along an AT&T ROW (id.).

[184] The Companies indicated that reliability concerns were addressed through the requirement for a substation and two interconnection lines as an underlying project approach uniformly applied to all routes (see Section IV.B) (Exh. BLK-BEC-14, at 4-13). Therefore, the Companies asserted that reliability differences were considered to be minor and relate to the differences between overhead and underground facilities (id.).

[185] ANP and BECo assigned a high tree clearing ranking to routes that required the clearing of less than two acres, a medium ranking to routes that required the clearing of between two and ten acres, and a low ranking to routes that required the clearing of more than ten acres (Exh. BLK-BEC-14, at 4-20). Each of the four underground alternatives required between 3.86 and 4.58 acres of tree clearing; the Mendon Overhead Loop and the Mendon Overhead Radial required 34.10 acres and 35.56 acres, respectively (Exh. HO-J-S-1.1). During the course of the proceeding, ANP and

(continued…)

(id.). ANP and BECo explained that each route/configuration received a score for each criterion based on a high, medium or low ranking, scored at two, one and zero points respectively (id. at 4-21).

ANP and BECo explained that their cost estimates for each routing option were based on the costs of: (1) material and equipment for the transmission lines, the substation, and the switching station; (2) construction; and (3) the purchase of land for a transmission corridor (id.).[186] The Companies then ranked the cost estimates as high, medium or low, based on the percentage difference between the cost of that route and the cost of the route with the lowest cost, or baseline cost (id. at 4-21).[187]

ANP and BECo stated that they ranked each criterion as very important, of moderate importance, or of minor importance, and assigned a weighting factor of three, two or one points to each criterion based on its classification (id. at 4-22). ANP and BECo indicated that, of the five community impact criteria, proximity to sensitive receptors and visual impact were considered very important; construction impacts on the traffic system and construction impacts

[185](...continued)
BECo revised the initial site selection scoring for tree clearing due to an error in the designation of high versus medium scores (Exhs. HO-J-S-1; HO-J-S-1.2). ANP and BECo also revised their tree-clearing estimates for the Mendon Overhead Loop, following a reconfiguration of that route; although the area to be cleared was reduced, the site selection score was not affected (Exh. HO-J-RR-8). The Siting Board notes that the tree clearing scores reflect only the tree clearing associated with the proposed transmission lines, and not the incremental tree clearing needed to accommodate the natural gas pipeline.

[186] The Companies' estimates of land acquisition costs for the alternatives ranged from $75,000 to $150,000 (Exh. BEC-BLK-14, at 4-21).

[187] The least-cost route, namely the Mendon Overhead Loop, had an estimated cost of $10.5 million; the cost of the other alternatives ranged from $12.9 million to $19.95 million (Exh. BLK-BEC-14, at 4-21). Alternatives with estimated costs 15 percent or less above the baseline cost received a high ranking; alternatives with estimated costs between 15 percent and 30 percent above the baseline cost received a medium ranking; and alternatives with estimated costs greater than 30 percent above the baseline cost received a low ranking (id.).

on residences were considered of moderate importance; and impacts of off-site operations was considered of minor importance (id. at Table 4-2). Thus the total potential weighted score for the community impact criteria was 22 (id. at Table 4-2). The Companies also indicated that of the four natural resources criteria, wetlands/floodplains and tree clearing were considered very important; surface waters was considered of moderate importance; and groundwater was considered of minor importance (id. at Table 4-3). Thus, the total potential weighted score for the natural resource criteria was 18 (id. at Table 4-3). Finally, cost was considered very important; thus, the total potential weighted score for cost was six (id. at Table 4-4).[188]

To determine the final scores for each route/configuration option, the Companies first calculated the weighted score for each of the three categories of screening criteria, then multiplied the individual score for each criterion by its weighting factor, and then expressed this weighted score as a percentage of the total potential weighted score for that category (id. at 4-22).[189] These percentages were converted into a final overall score by multiplying each percentage by a weighting factor for that category (id.). ANP and BECo asserted that the cost considerations should be outweighed by both environmental and community impacts, and therefore assigned overall weights of 45 percent for community impacts, 35 percent for natural resource impacts, and 20 percent for cost (id.).

The Mendon Overhead Loop scored the highest of the six alternatives and was selected as the primary route configuration (id.).[190] The Companies selected the fifth-ranked

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188 All of the underground alternatives had estimated costs which were at least 40 percent greater than the baseline cost (Exh. BLK-BEC-14, at 4-21). The Siting Board notes that the cost of an underground transmission line generally is at least double that of a similar overhead line.

189 For example, the Mendon Overhead Loop received a weighted score of 19 for community impacts; since the total potential weighted score for community impacts is 22, the final community impacts score for the Mendon Overhead Loop was 19/22, or 86 percent (Exh. BKL-BEC-14, at Table 4-2).

190 Based on the revised scores provided by ANP and BECo, which included the change in (continued...)

alternative, the Spruce Street Underground Radial, as its noticed alternative, arguing that the second through forth-ranked alternatives would not meet the Siting Board's requirement that the noticed alternative be geographically distinct from the primary route,[191] and further, that none of these alternatives permits the primary route and the proposed power plant to be located in the same municipality (id.). The Companies asserted that the Spruce Street Underground Radial was a viable, feasible, and environmentally sound alternative to the primary route (id. at 51-52).

b. Analysis

ANP and BECo have developed criteria for identifying and evaluating route options that address natural resource issues, land use issues, human environmental issues and cost -- four of the five general types of criteria that the Siting Board has found to be appropriate for the siting of transmission lines and related facilities. See 1998 NEPCo Decision, EFSB 97-3, at 43; 1997 BECo Decision, EFSB 96-1, at 68; New England Power Company, 4 DOMSB 109, 167 (1995) ("1995 NEPCo Decision"). The Companies indicated that they did not evaluate reliability as part of their route selection process because they had already determined that all of the selected options for connecting the proposed generating facility to BECo's Line 336 would have similar levels of reliability. Based on a review of project approach in Section IV.B, above, the Siting Board accepts the Companies' assertion that all identified routing/ configuration options are likely to be equally reliable.

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[190](...continued)
the tree clearing scores, the final numerical scoring listed from highest to lowest was: Mendon Overhead Loop (primary route) - 76, Mendon Underground Radial - 64, Mendon Overhead Radial - 64, Pine Needle Underground Radial - 58, Spruce Street Underground Radial (alternative route) - 22, and Elm Street Underground Radial - 16 (Exh. HO-J-S-1.2).

[191] The Companies asserted that the Siting Board has not required a noticed alternative to be the second-best identified alternative (Tr.-J-1, at 49).

To identify route options for further evaluation, ANP and BECo defined a facility study area that would encompass all viable routes from the proposed ANP Blackstone facility to BECo's Line 336. The Companies then developed a list of criteria consisting of community impacts and natural resources and assigned scores for each of the criteria which reflected the relative impacts of various types of routing and configuration options. The Siting Board notes that the weighting of the specific environmental criteria for community and natural resource impacts adequately reflected their relative significance.

With respect to scoring, however, the parameters used to generate scores (i.e., parameters distinguishing high, medium or low ratings) with respect to two of the criteria -- acres of trees cleared and cost -- appear not to have been well calibrated to the likely ranges for such criteria in the study area. Specifically, the scoring for tree clearing required that not more than two acres of trees be cleared in order to receive a high rating, and that two to not more than ten acres be cleared to receive a medium ranking. The record does not explain how these parameters were developed. However, the Siting Board concludes that the differential environmental impacts resulting from the clearing of 35 acres (for overhead routes) as compared to between 3.5 and 4.5 acres (for the underground routes) was not reasonably reflected in the medium score assigned to the four underground routes. Given the significant difference in cleared acreage, a more appropriate scoring might have been to assign a high score to the underground routes, while maintaining a low score for the above ground routes.

With respect to cost, the scoring required a cost of not more than 15 percent above baseline for a high ranking, and a cost of over 15 percent but not more than 30 percent above baseline for a medium ranking. As has been typical in other transmission line reviews, however, the cost difference of the highest cost alternative above baseline -- here nearly 95 percent -- is well above the 30 percent limit for a ranking of better than low.[192] Thus, the

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[192] The routing choices in past cases have reflected the following cost ranges: $19.9 to $35.8 million, or 80 percent (1998 NEPCo Decision, EFSB 97-3, at 41); $12.5 to $18.6 million, or 49 percent (1997 BECo Decision, EFSB 96-1, at 67); $7.5 to $14.9 million, or 99 percent (1997 ComElec Decision, EFSB 96-6, at 88); $2.0 to $5.7 (continued...)

Companies' criteria would not, for example, distinguish between two identical routes, costing $13.7 million and $19.95 million, respectively. Use of a higher limit, better calibrated to typical ranges of cost among alternatives, might have resulted in a medium score for one or more of the underground routes.[193] In general, the Siting Board notes that where routing and design choices are likely to result in a sizeable range of environmental impacts or costs for particular criteria, care should be taken to calibrate scoring parameters to avoid understating differences that are likely to arise.

Changes in the calibration of scores, combined with a rerouting of the Mendon Underground Radial several hundred feet to the east,[194] could have resulted in an underground route receiving a score comparable to or slightly higher than that of the Mendon Overhead Loop. However, the difference between the actual score of the Mendon Overhead Loop and the highest score likely to be received by a hypothetical rerouted Mendon Underground Radial is quite small. In addition, the Siting Board recognizes that a numerical ranking exercise, while important, is only the first step in the evaluation of potential routes. As discussed in Section IV.D.3.a.2, below, the Companies substantially reduced the tree clearing associated with the Mendon Overhead Loop as they refined the route. Consequently, the Siting Board concludes that the Companies did not overlook a clearly superior alternative.

Therefore, despite the Siting board's concerns about the Companies development and subsequent application of the rankings for tree scoring and cost, the Siting Board finds that ANP and BECo have developed and applied a reasonable set of criteria for identifying and

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[192](...continued)
million, or 270 percent (1995 NEPCo Decision, 4 DOMSB at 169).

[193] The Siting Board notes that changing an alternative's cost from "low" to "medium" would increase its overall final score by 10 points out of a possible total of 100.

[194] The final score of the Mendon Underground Radial alternative could be increased by rerouting it to the east, away from existing residences. This could increase its ratings for both proximity to sensitive receptors and construction impacts on residences from medium to high, thus raising its final score by approximately 10 points out of a possible total of 100.

evaluating alternatives to the proposed project in a manner which insures that it has not overlooked or eliminated any alternatives which are clearly superior to the proposed project.

3. Geographic Diversity

ANP and BECo considered six routing/configuration alternatives for its proposed transmission line. Three of the routes are in essentially the same location and vary only by design. The Siting Board acknowledges that the combination of the short route length, approximately one mile, and the discrete start and end points, necessarily limits the number of available routes with significant geographic diversity.

ANP and BECo presented one noticed alternative route that differs significantly from the primary route for its entire length. ANP and BECo specifically selected the noticed alternative route because it was geographically diverse from the primary route, even though it scored fifth out of the possible six routes. The Siting Board agrees with the Companies that our standard of review, as currently stated, requires the noticing of an alternative route with some measure of geographic diversity and that the second-, third-, and forth-ranked routes may not provide this diversity. At the same time, we are concerned that the underground alternative noticed by the Company is significantly weaker than both the Mendon Underground Radial and the Pine Needle Underground Radial with respect to both community and natural resource impacts. Evaluation of a strong underground route is particularly important in cases, like this instant case, where a new ROW is being created. Consequently, the Siting Board will review an underground version of the primary route as a design alternative in Section IV.D.3, below.

The Siting Board notes that, when appropriate, transmission line proponents have noticed three or more routes, in order to capture both the elements of environmental impacts and geographic diversity . See 1997 ComElec Decision, EFSB 96-6, at 58-59; Norwood Decision, EFSB 96-2, at 2-3; 1996 NEPCo, EFSB 95-2, at 1-2; 1995 NEPCo Decision, 4 DOMSB, at 114. (See also, Berkshire Gas Company, 23 DOMSC, at 300-301 (1991)). In future cases where design issues could significantly affect the environmental impacts and costs of a proposed transmission project, the Siting Board expects the proponent either to (1) notice three alternatives, or (2) notice two geographically distinct routes and provide the Siting Board with comprehensive information regarding the design alternatives for the primary route.

Based on the foregoing, the Siting Board finds that ANP and BECo have 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 ANP and BECo developed and applied a reasonable set of criteria for identifying and evaluating alternatives to the proposed project in a manner which insures 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 ANP and BECo have identified a range of practical transmission line routes with some measure of geographic diversity.

Accordingly, the Siting Board finds that ANP and BECo have examined a reasonable range of practical facility siting alternatives.

D. Environmental Impacts, Cost, and Reliability of the Proposed and Alternative Facilities

1. Standard of Review

In implementing its statutory mandate to ensure a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting 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. 1998 NEPCo Decision, EFSB 97-3, at 45; 1997 BECo Decision, EFSB 96-1, at 72; 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. 1998 NEPCo Decision, EFSB 97-3, at 45; 1997 BECo Decision, EFSB 96-1, at 72; 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. 1998 NEPCo Decision, EFSB 97-3, at 45-46; 1997 BECo Decision, EFSB 96-1, at 72; 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 reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. 1998 NEPCo Decision, EFSB 97-3, at 46; 1997 BECo Decision, EFSB 96-1, at 73; 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. 1998 NEPCo Decision, EFSB 97-3, at 46; 1997 BECo Decision, EFSB 96-1, at 73; 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 project 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. 1998 NEPCo Decision, EFSB 97-3, at 46; 1997 BECo Decision, EFSB 96-1, at 73; 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. 1998 NEPCo Decision, EFSB 97-3, at 46-47; 1997 BECo Decision, EFSB 96-1, at 73; 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 ANP'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. Description of the Proposed and Alternative Facilities

a. Proposed Facilities

The Companies propose to construct two 1.1-mile long, overhead 345 kV transmission lines in Blackstone and Mendon and an associated 345 kV transmission substation within the plant footprint that will connect the proposed ANP Blackstone generating plant to the regional transmission system in Mendon (Exh. BLK-BEC-14, at 1-3, 3-2; Tr.-J-1, at 77).

The primary route extends from the new substation within the plant switchyard in Blackstone through woodland, crossing the Mendon town line, and terminates at BECo ROW 13 (Exhs. BLK-BEC-14, at 2-2; BLK-BEC-11). The Companies indicated that pairs of "H-Frame" wooden poles, similar to those used presently on ROW 13, would support the two new transmission interconnect lines along most of the primary route's 1.1-mile length (Exh. BLK-BEC-13; Tr.-J-1, at 25-26).

b. Alternative Facilities

The Companies stated that the alternative route would be a double circuit radial transmission interconnect consisting of overhead and underground segments along its approximately 0.9-mile length (Exh. BLK-BEC-14, at 1-10 to 1-12). The Companies stated that the initial overhead route segment would traverse the plant site from the plant's substation switchyard and exit the plant site in a westerly direction to the treeline northeast of Fish Pond, where it would transition to underground (id.). The underground facilities would then proceed beneath the Mill River and its associated Riverfront Zone, wetlands, and adjacent woodland to the eastern end of Spruce Street (id.). From here, lines would run beneath the entire length of Spruce Street, cross Blackstone Street and a private parcel, and terminate at a new substation located on BECo's ROW 13 (id.).

3. Analysis of the Proposed Facilities Along the Primary Route

The Companies have presented two noticed route alternatives: the 1.1-mile overhead primary route and the 0.9-mile part-overhead, part underground alternative route. In this section, the Siting Board evaluates the environmental impacts, cost and reliability of the proposed facilities along the primary route, in order to determine whether the proposed facilities achieve the appropriate balance among environmental impacts, cost, and reliability.

The proposed use of the overhead primary route would require creating a new transmission corridor, and include siting 345 kV lines across a currently wooded area not occupied by existing transmission lines. Given the environmental concerns that often arise when an above-ground transmission line is proposed along a new transmission corridor, the Siting Board considers, as part of its analysis of the proposed facilities along the primary route, whether alternative facility designs are available that would better achieve the appropriate balance among environmental impacts, cost and reliability. See, e.g., Turners Falls, 18 DOMSC at 141, 174-194; Commonwealth Electric Company, 17 DOMSC at 249, 297-298, 303-304, 318-324 (1988); Hingham Municipal Lighting Plant, 14 DOMSC at 7, 29-31 (1986). In this review, the Siting Board considers two alternative facility designs: (1) use of double-circuit steel structures, instead of the proposed wooden H-frame structures, to support the proposed overhead transmission lines; and (2) use of underground transmission lines instead of the proposed overhead transmission lines.

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

(1) Water Resources[195]

ANP and BECo stated that no mapped aquifers, and no identified surface water resources including streams, rivers, ponds, or lakes, are located within the vicinity of the primary route (Exhs. BLK-BEC-14, at 4-7, 5-2; HO-J-E-3.1). ANP also stated that the proposed transmission lines would have no permanent impact on wetlands or vegetative areas within wetlands (Exhs. HO-J-E-2(b), at 2; HO-J-E-3). The Companies' witness, Mr. Barry, added that the Companies would avoid use of guy wires in extensive wetland areas by using a steel angle structure at the angle location nearest to the plant switchyard (Exh. HO-RR-J-1, att. 1.1; Tr.-J-1, at 31-33).

The record indicates that, with use of the currently proposed alignment, permanent impacts to wetland areas along the primary route would be avoided. The record also indicates that the Companies plan to use steel support structures for the proposed transmission lines in proximity to a wetland area along the primary route in order to eliminate the need for ground-anchored guy wires therein.[196] In addition, construction access to the new ROW would be via

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[195] Impacts to water resources include impacts to wetlands, surface water, groundwater, and wells, as applicable.

[196] In comparing the proposed use of overhead lines to use of underground lines along the primary route, the Companies indicated that use of underground lines would require temporary construction disturbance, as well as construction of a permanent access road, (continued...)

the proposed generating facility site and Bates Road in Mendon, thereby minimizing potential temporary impacts to wetlands.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to water resources.

(2) Land Resources

The Companies indicated that installation of the proposed electric and gas transmission facilities along the primary route would require the clearing of a total of 25.62 acres of trees (Exh. HO-RR-J-8). Of these 25.62 acres, 20.49 acres are attributable to the overhead electric lines supported by wooden H-frame structures, 4.64 acres for clearing ROW for the proposed generating facility's gas interconnect line, and 0.49 acres are attributable to temporary clearing during construction of the gas interconnect line (Exh. HO-RR-J-8).[197] The Companies indicated that they would offset tree clearing impacts along the primary route by planting 17.01 acres of trees within the generation facility site (id.).

The Companies indicated that the expected clearing could be reduced by about eight acres, to a total of approximately 17 acres, if double circuit steel structures were used instead

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[196](...continued)
at an intermittent stream crossing (Exh. HO-J-E-2). The Siting Board notes that an alignment parallel to the proposed gas interconnect line, which diverges north from the primary route for a length of 2000 feet nearest the generating facility, would serve to avoid placement of underground lines in the nearby extensive wetland areas (Exh. HO-J-E-3.1, general plan).

[197] The Companies stated that the 20.49-acre estimate reflects a 25-foot shift in the lines' alignment along the northern segment of the route in Mendon (Exh. HO-RR-J-8, at 2). The Companies further stated that the 25-foot shift is made possible by a change in the location of the proposed gas interconnect pipeline closer to the existing Tennessee pipeline along this segment of the route (id.). The Companies indicated, however, that in the event the proposed pipeline's realignment does not occur, the tree clearing impact for the overhead electric segment of the joint ROW would increase from 20.49 acres to 21.30 acres (id.).

of the wooden H-frame structures (id.; Exh. HO-J-E-5, at 2).[198] Alternatively, the Companies indicated that the clearing could be reduced to approximately nine acres if underground lines were used (Exhs. HO-J-R-1; HO-J-S-1.1, at 9).[199]

The Companies stated that while construction of the proposed facilities would result in dust, noise, and vehicle emissions in the vicinity of the primary route, there would be minimal impacts on plant and animal species in the vicinity of the primary route (Exh. BLK-BEC-14, at 5-9). The Companies explained that the proposed substation would be located within the previously cleared plant switchyard area, and the common utility ROW would be largely adjacent to an existing, cleared gas pipeline corridor (id.).[200] The Companies stated that no endangered, threatened, or special plant or animal species would be affected by the construction activities in the vicinity of the primary route (id.). The Companies also indicated that no significant historical or archaeological[201] resources were identified by the Massachusetts Historical Commission in the immediate vicinity of the primary route (Exh. BLK-BEC-16).

The Companies stated that following construction, the cleared ROW would be allowed to revegetate with shrub and herbaceous species, with maintenance of vegetative growth

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198 The Companies explained that a double-circuit structure can be constructed on a 150-foot-wide ROW while the two proposed H-frame structures require a ROW width of 250 feet (Exh. HO-J-E-5, at 2).

199 The Companies indicated that use of underground lines would allow the width of the ROW to be reduced to 30 feet (Exh. HO-J-E-2, at 3). However, the Companies noted that use of underground lines would require the installation of an additional substation adjacent to the interconnection point on ROW 13, and that up to two acres of trees would be cleared to construct that substation (Exh. BLK-BEC-14, at Fig 4-3).

200 The Companies observed that the temporary impacts to plants and animals as a result of constructing the proposed facilities along the primary route would be similar to on-going impacts of the sand and gravel operations at the nearby Kimball site (Exh. BLK-BEC-14, at 5-9).

201 The Companies noted that an archaeological investigation was completed by the Public Archaeological Laboratory, Inc., with the associated fieldwork summary concluding that there are no significant archaeological properties in the overall project area, which includes both the primary and alternative routes (Exh. BLK-BEC-16).

conducted on a four year cycle by mechanical methods, as is presently done on BECo's ROW 13 (Exh. BLK-BEC-14, at 5-9 to 5-10). ANP stated it has committed to acquire approximately 40 acres of prime residential development land in Mendon located between the existing Tennessee ROW and the residential neighborhood along Colonial Drive for open space preservation (id.; Exhs. HO-RR-J-8, at 2; BLK-BEC-15, att.; Tr.-J-1, at 79).[202]

The record demonstrates that although the Companies have made a good faith commitment both to partially replicate the expected tree clearing loss via on-site planting, and to ensure the future preservation of an additional 40 acres of developable land in the Town of Mendon,[203] there would be a significant tree clearing impact -- over 25 acres -- under the primary route. This impact could be considerably reduced through the use of double-circuit steel structures or underground lines, both of which can be sited within a narrower corridor. The Siting Board therefore concludes that use of double-circuit steel structures or underground lines would be preferable to the use of wooden H-frame structures with respect to land resources.

The record also indicates that no rare or endangered animal or plant species, or historical or archaeological resources are at risk due to the construction or operation of the proposed facilities along the primary route. Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to species habitat and historical and archaeological resources.

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202 The Companies' witness, Ms. Chan, testified that an aggregate land parcel of at least 60 acres would be purchased in Mendon (Tr.-J-1, at 79). The Companies indicated that approximately 18 of these acres would be cleared to accommodate the gas and electric interconnects, and that two existing AT&T easements crossing the parcels would total nearly two acres, leaving a balance for preservation of approximately 40 acres (id.; Exhs. BLK-BEC-15, att.; HO-RR-J-8, at 2).

203 The Siting Board notes that, although the Companies are committed to providing 40 acres of preserved land, there is uncertainty in assessing the likelihood that the land would otherwise be developed, and when.

(3) Land Use

The Companies stated that land uses along the primary route include active sand and gravel removal operations in the vicinity of the proposed substation at the generating plant site, and wooded, undeveloped land with existing utility easements along the remaining portion of the route (Exh. BLK-BEC-14, at 5-10). The Companies indicated that the primary route runs immediately adjacent to an existing Tennessee pipeline ROW for approximately the last 2,000 feet of its length up to BECo ROW 13 (Exh. BLK-BEC-11). The Companies stated that, under the primary route, the proposed transmission lines could share a 275-foot wide corridor with the plant's proposed gas pipeline interconnect for a majority of the route's length (id.; Exh. BLK-BEC-14, at 5-10).

The Companies stated that because the facilities are located away from all roadways, traffic impacts associated with the construction along the primary route would be minimal and confined to minor vehicle traffic accessing the proposed ROW either from the generating facility site or from Bates Road in Mendon (id. at 5-18). With respect to noise, the Companies stated that, other than occasional noise as a result of maintenance activities, no permanent operating noise sources would be located outside of the plant site (id. at 5-14, 5-17). The Companies stated that temporary noise from construction of the substation within the plant switchyard would likely be indistinguishable from construction activities at the proposed plant (id. at 5-17). The Companies further stated that construction noise associated with the installation of the two transmission lines outside of the plant switchyard would likely be minor at proximate residences due to the distance -- at least 650 feet -- from homes along the primary route (id.; Tr.-J-2, at 101-104). With respect to safety, the Companies stated that the entire perimeter of the substation area would be enclosed by an eight-foot chain-link fence with three strands of barbed wire across the top (Exh. BLK-BEC-14, at 1-10).

ANP indicated that construction of the proposed substation and switchyard would occur over 14 months, and the proposed interconnect would be completed within 21 months, concurrent with completion and commercial operation of ANP's proposed generating plant (Exhs. BLK-12.2, at 9-9; HO-V-2).[204]

The record demonstrates that the land use impacts of the construction of the proposed overhead transmission lines would be temporary and minimized along the primary route. The impacts of the substation would be minimized due to its location within the generating plant switchyard and adjacent to unrelated, active sand and gravel operations. As the primary route extends towards BECo ROW 13, the wooded and undeveloped land character and distance of over 600 feet to the closest residence both would serve to minimize the construction impacts associated with the proposed transmission lines.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land use.

(4) Visual

The Companies stated that the potential visual impacts of the substation would be mitigated through its location within the proposed generating facility site in Blackstone (Exhs. HO-J-E-2, at 4-5; BLK-BEC-14, at 5-12). The Companies indicated that the substation would be relatively small compared to the other generating facility structures (Exh. BLK-BEC-14, at 5-3, Fig. 5-1). The Companies indicated that two narrow lightning shield masts, up to 100 feet in height, would be the tallest structures within the fenced substation area (id. at 1-8 (Fig. 1-2), 1-10).[205]

The Companies stated that the location of the proposed transmission lines within a wooded and undeveloped area ensures that, at their highest point of visibility, only the upper

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204 In comparing the proposed use of overhead lines to use of underground lines along the primary route, the Companies indicated that installation of the ROW 13 substation would require construction activity over a 12-15 month period, with access from Bates Road (Exh. HO-J-E-2).

205 ANP indicated that taller structures within the plant site would include the 180-foot exhaust stacks and the 110-foot air-cooled condensers (Exhs. BLK-1, at 6-68; HO-EV-8; HO-RR-53).

portions of the wooden H-frame structures would be visible to the community (id. at 5-12; Exh. HO-J-E-2, at 4). The Companies provided photographs of two viewsheds of the proposed transmission lines as they would be seen (1) from Bellingham Road at Marzakowski Way, approximately 1,000 feet southeast of the proposed transmission lines, and (2) from the intersection of Blackstone and Spruce Streets, approximately one-half mile to the west (Exhs. BLK-BEC-14, at 5-13; HO-J-E-7, att. E-7.1). The photographs indicate that the upper third of the wooden H-frame structures would be visible above the tree line from Bellingham Road (Exh. HO-J-E-7, att. E-7.1). The Companies stated that the Bellingham Road viewshed represents a vantage point with the highest visibility of the transmission lines (id.). The Companies' photograph of the viewshed from the intersection of Blackstone and Spruce Streets indicates a noticeable, but less intrusive view of the topmost portions of the proposed wooden H-frame structures above the tree line (Exh. BLK-BEC-14, at 5-13).

The Companies' witness, Mr. Barry, testified that wooden H-frame structures would be used along most of the primary route (Exh. HO-RR-J-1, att. 1.1; Tr.-J-1, at 31-34). However, he indicated that non-guyed, weathering-steel monopoles, reddish-brown in appearance, would be used in two locations: (1) at the first angle in the interconnect, where the lines exit the plant switchyard and approach an extensive wetland area; and (2) at the point where the proposed transmission lines would meet BECo ROW 13 (Tr.-J-1, at 33). The Companies stated that the proposed wooden H-Frame structures were selected for compatibility with similarly constructed wooden H-frame structures used on BECo's existing Line 336 (Exhs. HO-J-E-5, at 2; BLK-BEC-14, at 5-12).[206]

The Companies considered the option of using double-circuit steel structures for the proposed transmission lines, and provided both narrative and viewshed information regarding

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[206] The Companies provided two drawings that depicted wooden H-frame structures -- one typical of the older structures used on existing Line 336, and the other typical of those that would be used for the proposed interconnect (Exhs. BLK-BEC-12; BLK-BEC-13). The Companies' witness, Mr. Barry, testified that the existing H-frame structures are approximately 90 feet high in the vicinity of the proposed interconnect's terminus at Line 336 (Tr.-J-1, at 24-25).

their potential visual impacts to the area (Exhs. HO-J-E-7, att. E-7.1; HO-J-E-5). The Companies stated that because the double-circuit steel structures would use vertically-arrayed conductors, they would be 50 feet taller than the 80-foot-high wooden H-frame structures, and thus would be significantly more visible in some locations (Exh. HO-J-E-5; Tr.-J-1, at 26). The Companies added that the introduction of a different configuration, i.e., double-circuit steel structures, in close proximity to the existing wooden H-frame structures of Line 336 would likely draw added attention to the new interconnect (Exh. HO-J-E-7).[207]

The Companies also considered the option of underground lines to interconnect the generating facility along the primary route (Exhs. HO-J-R-1; HO-J-E-2). The Companies stated that use of underground lines would have the advantage of eliminating views of the proposed overhead lines, but would require construction of a second substation at the interconnection point (id.). The Companies indicated that the substation would be sited adjacent to ROW 13, limiting the potential for views of the substation along the ROW (Exhs. BLK-BEC-14, at 4-12; HO-J-E-2, at 4).

The record demonstrates that the primary route outside of the generating facility footprint traverses a forested area bounded generally by a Tennessee gas pipeline ROW to the east and BECo's ROW 13/Line 336 to the north. Although the proposed transmission lines would be partially visible, the record suggests that the presence of existing utility uses and the wooded nature of the area would largely mitigate the views of the proposed interconnect lines along the primary route. The record also shows that the wooden H-frame structures would blend in appearance where visible from 1,000 feet or more, due to both the forested setting in which they would be viewed, and their limited typical height above ground of 80 feet. The proposed wooden H-frame structures would be compatible with the existing support structures along ROW 13, although marginally lower in height. The special weathering-steel angle supports used in two areas along the route, while different in appearance from the tangent

[207] The Companies indicated that the base finish of the double-circuit steel structures, in the absence of any final finish applied for aesthetic reasons, would be weathering steel (Exh. HO-J-E-7).

structures typically used, also would have a finish that minimizes their presence in the overall viewshed.

The record also demonstrates that, at the substation terminus of the proposed interconnecting lines, the visual impact of the substation and switchyard would be minimized given their location within the proposed generating facility site. The immediate facility site area includes sand and gravel operations, and the incremental impact of the substation facilities would be limited as part of an overall viewshed of a larger, associated generating facility. The narrow, lightning shield masts planned within the substation likely would not be noticeable outside the immediate area.

The record also indicates that double-circuit steel structures, which would be 50 feet taller than the proposed wooden H-frame structures, likely would be visible from more locations, and be more intrusive based on their greater protrusion above the horizon. The final finish of the steel supports could serve to lessen this impact, given the terrain and sky background against which the supports would be viewed. Nonetheless, the wooden H-frame structures would blend better overall, given their significantly lower height and more natural appearance. The Siting Board therefore concludes that the use of wooden H-frame structures would be preferable to the use of double-circuit steel structures with respect to visual impacts.

Finally, the record indicates that the visual impacts of the proposed overhead transmission lines could be avoided by use of underground lines. Use of underground lines would require installation of an additional substation adjacent to ROW 13, not required with use of overhead lines. However, the additional substation would be sited off the open ROW, at a point well removed from any residences, built-up areas or roadways, and therefore would have little if any visual impact. The Siting Board therefore concludes that the use of underground lines would be preferable to the use of wooden H-frame support structures with respect to visual impacts.

(5) Magnetic Field Levels

The Companies argued that magnetic field levels resulting from the operation of the proposed facilities would be so small as to be virtually indistinguishable from background levels at area residences (Companies Brief at 44). Mr. Charlebois testified that the closest residences would be located in the vicinity of Pine Needle Drive in Mendon, at a distance of approximately 650 feet from the ROW (Tr.-J-2, at 97-104). Dr. Bailey testified that the edge-of-ROW levels along the new utility corridor would be 31 mG on the west side and 28 mG on the east side (Tr.-J-2, at 107-109).[208] Dr. Bailey indicated that the magnetic field levels at the closest residences in the vicinity of Pine Needle Drive in Mendon would be very low to essentially indistinguishable from background levels present (id. at 108-109).

The Companies explained that the use of double-circuit steel structures rather than wooden H-frame structures would result in lower EMF levels due to closer conductor spacing and greater flexibility to incorporate phase arrangements resulting in field cancellation (Exh. HO-J-E-5, at 2). However, the Companies asserted that since there are no residences adjacent to the ROW, or ROW-width restrictions, there is no reason to create a visual impact associated with using the double-circuit steel structures in order to lower EMF levels (id.).

In a previous review of proposed 345 kV 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"). Here, while magnetic field levels are high within the ROW, due to the interconnect's loop design carrying both plant output and power flows from existing Line 336, edge-of-ROW levels would remain well below the levels found acceptable in the 1985 MECo/NEPCo Decision. In addition, the Siting Board agrees with the Companies' position that any advantage of double-circuit steel structures in reducing potential magnetic field levels would be very limited, and outweighed by added visual impacts, given that the associated

208 The Companies indicated that the maximum magnetic field level within the ROW would be 315 mG (Exh. HO-J-E-1, at 2).

levels at the nearest residences would be very low to indistinguishable using the proposed wooden H-frame structures.[209]

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to magnetic fields.

(6) Conclusions on Environmental Impacts

In Section IV.D.3.a, above, the Siting Board has reviewed the information in the record regarding environmental impacts of the proposed facilities along the primary route and any potential mitigation measures. The Siting Board finds that the Companies have 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, reliability, and cost would be achieved.

In Section IV.D.3.a, above, the Siting Board has found that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to water resources, species habitat and historical and archaeological resources, land use, and magnetic field impacts.

The Siting Board also has concluded that: (1) the use of double-circuit steel structures or the use of underground lines would be preferable to the use of wooden H-frame structures with respect to land resources; and (2) the use of wooden H-frame structures would be preferable to the use of double-circuit steel structures with respect to visual impacts, but the

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209 The Companies indicated that with use of underground lines, maximum magnetic field levels would be 3.7 mG above proposed transmission lines and 1.5 mG at the edge of the ROW (Exh. HO-J-E-1) (see Section IV.D.4.a.(5), below). As with use of double-circuit steel structures, use of underground lines likely would result in lower magnetic fields than use of wooden H-frame structures; however, any advantage of underground lines in reducing magnetic field levels would be very limited given the low to indistinguishable levels at the nearest residences with use of wooden H-frame structures.

use of underground lines would be preferable to the use of overhead lines with wooden H-frame support structures, with respect to visual impacts.

Underground lines would provide significant advantages over wooden H-frame structures with respect to two types of environmental impact, tree clearing and visual impact, with minor offsetting environmental disadvantages.[210] The Siting Board therefore concludes that underground lines would be preferable to wooden H-frame structures with respect to environmental impacts.

Double-circuit steel structures and wooden H-frame structures would provide offsetting advantages with respect to tree clearing and visual impacts, respectively. To determine whether environmental impacts would be minimized, the Siting Board must balance the offsetting environmental advantages of double-circuit steel structures and wooden H-frame structures.

The record indicates that the additional eight acres of tree clearing for the proposed wooden H-Frame structures, although significant, would be located well away from residences, built-up areas and roadways. Further, the proposed planting of new trees nearby -- on the generating facility site -- would partially offset tree clearing for the interconnect corridor. In terms of CO_2 offset plans, the Siting Board has required in Section III.B.2.A, that the CO_2 sequestration lost as a result of tree clearing for the proposed ANP Blackstone project, including interconnect facilities, be offset on a one-to-one basis through upward adjustment of ANP's CO_2 offset mitigation.

With respect to visual impacts, the record establishes a clear preference for wooden H-frame structures, relative to double-circuit steel structures, based on their significantly lower height and more natural appearance. In Section III.B.2.C, above, the Siting Board directed ANP to provide off-site tree planting to mitigate visual impacts of the proposed generating

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210 Minor disadvantages include the need to construct the underground lines and an access road across an intermittent stream (see Section IV.D.3.a.(1), above), and the need to conduct construction at the ROW 13 substation site over a 12-15 month period (see Section IV.D.3.a.(3), above).

facility and related facilities, if requested by residents or municipal officials. While potentially effective in reducing visual impacts where implemented, however, such mitigation is unlikely to address visual impacts in all affected locations; further, to the extent mitigation consists of tree and shrub plantings, a number of years may be required for some plantings to mature in order to fully accomplish their intended purpose. Thus, while mitigation would be available to address visual impacts of overhead transmission lines, it would not serve to negate the clear advantage of lower H-frame structures in minimizing visual impacts.

The Siting Board therefore concludes that the advantage of the proposed wooden H-frame structures with respect to visual impacts outweighs the advantage of double-circuit steel structures with respect to tree clearing. The Siting Board therefore concludes that the use of wooden H-frame structures would be preferable to the use of double-circuit steel structures with respect to environmental impacts.

b. Reliability

The Companies asserted that the proposed transmission lines would be more reliable when placed on wooden H-frame structures than when placed on double-circuit steel structures (Exh. HO-J-R-3; Tr.-J-1, at 63-65). The Companies explained that a substation or generator is more reliably operated within a system when connected via two single-circuit lines on separate support structures than via two lines on the same double-circuit structures, because, if a double-circuit structure is used, a single event such as a lightning strike could result in a simultaneous outage of both lines (Exh. HO-J-R-3, at 2). The Companies noted that NEPOOL system operating criteria requires dispatchers to assume the loss of both lines of a double-circuit line in a single contingency (Exh. HO-J-E-5, at 2).

The Companies acknowledged that good engineering practice such as the installation of differential insulation, underslung ground wire, and increased tower grounding can decrease the likelihood of a simultaneous outage of lines on a double-circuit structure (Exh. HO-J-R-3, at 2).[211] However, the Companies' witness, Mr. Barry, testified that a single event, such as a lightning strike affecting both lines on a double-circuit system, would occur approximately once every twenty years (id. at 66). He also testified that a lightning strike affecting either a single circuit line or one side of a double-circuit line would occur approximately once every ten years (Tr.-J-1, at 64-66). The Companies stated that double-circuit outages can also be caused by structure component failures that, while less likely to occur than lightning incidences, generally take much longer to repair (Exh. HO-J-R-3, at 3).[212]

The record demonstrates that there is a small, but nonetheless quantifiable, reliability advantage associated with the use of wooden H-frame structures rather than the taller, double-circuit steel structures. The Siting Board notes that either type of overhead transmission lines would incorporate a loop configuration, and therefore would carry both the output of the proposed ANP generating facility and the additional power flows along Line 336. Therefore, a single event affecting both lines on a double-circuit structure, although occurring once in twenty years, assumes greater significance given the exposure of large magnitudes of power and commensurate area of service. In contrast, a single event affecting either of the proposed transmission lines, with the H-frame support structures independent to each line, would allow the remaining line to deliver the plant's output to the section of the regional 345 kV transmission system not affected by the event, thereby ensuring reliability of system operation.

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211 The Companies stated that metal structures generally carry a slightly greater risk of lightning susceptibility than wooden structures due to the insulating value of a wooden structure's crossarm, but added that the effect is not significant (Exh. HO-J-R-3, at 3). However, the Companies also stated that the risk of a lightning outage on a structure increases with structure height (id.). The Companies added that double-circuit structures, being nearly 50 percent taller than the wooden H-frame structures, would be more susceptible to such incidents (id.).

212 The Companies stated that failure of the static wire is an example of a non-lightning-related incident that could trigger a double-circuit outage (Exh. HO-J-R-3, at 3).

The record also demonstrates that use of underground lines, incorporating a radial configuration with a second substation on ROW 13, would provide comparable reliability to the proposed use of overhead lines with wooden H-frame structures. Accordingly, based on the record above, the Siting Board finds that the Companies' proposed use of wooden H-frame structures would be preferable to the use of double-circuit steel structures and comparable to the use of underground lines with respect to reliability.

c. Cost of the Proposed Facilities along the Primary Route

The Companies estimated the total cost for installation of the proposed transmission lines along the primary route at $10.5 million (Exh. BLK-BEC-14, at 4-21).

The Companies indicated that the installation cost of the proposed transmission lines on double circuit structures would be essentially equal to that with use of wooden H-frame structures (Exh. HO-J-E-5, at 2; Tr. 1, at 61). However, the Companies asserted that use of double-circuit steel structures would result in additional costs related to NEPOOL's system operation and dispatch functions (Exh. HO-J-E-5, at 2; Tr. 1, at 61-65). Specifically, the Companies' witness, Mr. Presume, indicated that if the planned north and south segments of BECo Line 336 were carried on one row of double-circuit steel structures, a single contingency such as a lightning strike could result in the loss to the regional transmission system of the capacity of both the ANP Blackstone and NEA generating facilities (id. at 64). However, if the north and south segments of the line were carried on separate wooden H-Frame structures, only the capacity of one of the two generating facilities would be at risk under a single contingency (id.).[213] Thus, use of double-circuit steel structures would require NEPOOL to plan for, and set the level of system reserve based on, a potentially larger single contingency

213 The Companies indicated that during an outage affecting one of the two proposed 1.1-mile transmission lines, use of the wooden H-frame structures would enable the ANP Blackstone facility to utilize the segment unaffected by the outage, thus maintaining ANP Blackstone's output to the regional transmission system (Exh. HO-J-E-5, at 2).

impact (id. at 64-65). Mr. Presume asserted that this difference in dispatch and reserve levels would have cost implications, although he was unable to quantify them (id. at 65).

The Companies indicated that the total cost for installation of underground lines, including substation facilities, would be much higher than that for installation of the proposed facilities along the primary route (Exh. HO-J-R-1).[214] The record demonstrates that, although the capital cost of the proposed transmission lines would be comparable with use of wooden H-frame structures and double-circuit steel structures, higher planning and operating costs would result from the double-circuit design. The record also demonstrates that use of underground lines could increase installation costs by up to 50 percent, compared to the proposed overhead lines with wooden H-frame structures. Therefore, the Siting Board finds that the wooden H-frame structures proposed by the Companies would be slightly preferable to double-circuit steel structures and preferable to underground lines with respect to cost.

The Siting Board also finds that the Companies have provided sufficient cost information for the Siting Board to determine whether an appropriate balance would be achieved between environmental impacts, reliability, and cost.

d. Conclusions

The Siting Board has found that ANP and BECo have provided sufficient information regarding the environmental impacts, reliability and cost 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 cost, reliability and environmental impacts would be achieved. The Siting Board also has found that the environmental impacts of the proposed

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214 In their site selection analysis, the Companies estimated a cost of $15.5 million for the Mendon Underground Radial, 48 percent higher than the cost for the proposed facilities along the primary route (Exh. BLK-BEC-14, at 4-21). The route of the Mendon Underground Radial and the primary route are comparable in length, have the same endpoints, and traverse similar wooded areas between the generating facility site and the interconnection point in Mendon (see Section III.C.2, above).

facilities would be minimized with respect to water resources, land use, magnetic fields, and historical and archeological resources.

The Siting Board has reviewed the relative reliability, cost and environmental impacts of overhead lines on wooden H-frame structures, overhead lines on double-circuit steel structures, and underground lines. In Sections IV.D.3.a, b, and c, above, the Siting Board concluded that wooden H-frame structures would be preferable to double-circuit steel structures with respect to environmental impacts, reliability and cost. Consequently, the Siting Board finds that the use of wooden H-frame structures would be preferable to the use of double-circuit steel structures.

The comparison between overhead lines on wooden H-frame structures and underground lines is somewhat more complex. In Sections IV.D.3.a, b, and c, above, the Siting Board concluded that underground lines would be preferable to overhead lines on wooden H-frame structures with respect to environmental impacts, that overhead lines on wooden H-frame structures would be preferable to underground lines with respect to cost, and that the two designs would be comparable with respect to reliability. In balancing the environmental benefits of underground lines against their additional cost, the Siting Board first notes that construction of underground, rather than overhead, lines is likely to increase the proposed facilities' cost by as much as 50 percent, or $5 million.

We also note that the additional tree clearing required for the overhead route, while significant, is mitigated by the fact that the primary route is located away from existing residences, built-up areas and roadways. In addition, ANP plans to offset in part the tree clearing by planting new trees at the generating facility site, and the Siting Board has accounted for the CO_2 sequestration lost to the tree clearing in its requirements for CO_2 mitigation (see Section III.B.2.a, above). Similarly, the Siting Board has required ANP to provide off-site mitigation for the visual impacts of both the proposed generating facility and the overhead transmission lines in Section III.B.2.c, above. While these mitigation measures do not eliminate the environmental disadvantages of overhead lines, they may reduce the impacts on the surrounding communities. Given the location of the primary route away from residences, built-up areas and roadways and the mitigation available to limit the environmental impacts of the overhead lines, the Siting Board concludes that the significant additional cost of underground lines is not warranted.

Consequently, the Siting Board finds that wooden H-frame structures would be preferable to underground lines. The Siting Board also finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to land resources, consistent with minimizing other environmental impacts, reliability and cost. The Siting Board further finds that the environmental impacts of the proposed facilities along the primary route would be minimized with respect to visual impacts, consistent with minimizing other environmental impacts, reliability and cost.

Accordingly, the Siting Board finds that the environmental impacts of the proposed facilities along the primary route, with wooden H-frame structures, would be minimized consistent with minimizing cost, and that the proposed facilities along the primary route, with wooden H-frame structures, would achieve an appropriate balance among conflicting environmental concerns as well as between environmental impacts, reliability, and cost.

4. Analysis of the Proposed Facilities Along the Alternative Route

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 petitioners have 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, reliability,[215] and environmental impacts. In

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215 As discussed previously in Section IV.B.3, above, the Siting Board does not consider the need for two substations, rather than a single substation, to be evidence of decreased system reliability based on the incremental exposure of the second substation to equipment failures. In the absence of any other evidence regarding the relative safety of the two routes, the Siting Board finds that the reliability of both routes is (continued...)

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. Finally, 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.

a. Environmental Impacts of the Proposed Facilities Along the Alternative Route

(1) Water Resources

The Companies stated that the proposed underground portion of the transmission lines along the alternative route would cross the Mill River and an associated mapped aquifer, wetlands, and adjacent woodland -- via directional drilling -- for approximately 1,300 feet (Exh. BLK-BEC-14, at 1-10, 4-7, 5-2, 5-8). The Companies estimated that a total of 0.15 acres of wetlands would be disturbed by the construction of the two underground transmission lines and the substation access road, of which 0.11 acres would be permanently altered for the substation access road (Exh. BLK-BEC-14, at 5-7). ANP stated that wetland replication would be further evaluated and restoration would be implemented in order to mitigate the impacts of facility construction and location (Exh. BLK-12.2, sec. 11.6).

In comparing the water resource impacts of the proposed facilities along the primary and alternative routes, the record demonstrates that while the primary route would have no such impacts, the alternative route would permanently alter nearly 5,000 square feet of wetlands and result in some additional temporary impacts. The Siting Board notes that there is also a greater potential risk to water resources under the alternative route due to the directional drilling required to cross the Mill River and associated wetlands.

Accordingly, the Siting Board finds that the primary route is preferable to the alternative route with respect to impacts to water resources.

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[215](...continued)
essentially equal, and does not further address the issue of reliability in the instant case.

(2) Land Resources

As discussed previously in Section IV.D.3.a.2, above, the Companies indicated that the electric and gas interconnects would share a common utility corridor along a significant portion of the primary route. In contrast, the Companies stated that the electric transmission line and gas pipeline interconnect facilities would have to use separate ROWs if the alternative route was selected for the transmission lines (Exh. BLK-BEC-14, at 5-10). The Companies indicated that a total of 10.5 acres of tree clearing would be required to accommodate the separate electric transmission line and gas pipeline interconnects if the alternative route was used for the transmission lines, as compared to 25.6 acres of tree clearing under the primary route (Exh. HO-RR-J-8, at 2).[216,217] The Companies indicated that they would offset tree clearing along the alternative route by planting 23.07 acres of trees within the boundaries of the generation project site[218] (Exh. HO-RR-J-8, at 3). The Companies stated that traditional cut and fill methods would be used along Spruce and Blackstone Streets and across a private parcel in order to reach a new substation on ROW 13, but that directional drilling would be used beneath the woodland portion of the alternative route, beyond the Mill River and wetland areas, in order to eliminate the need to clear a transmission corridor through such sensitive areas (Exh. BLK-BEC-14, at 1-10, 5-10).

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216 The Companies indicated that selection of the alternative route would require approximately 4.6 acres of tree clearing for the electric interconnect, while the gas pipeline interconnect would require an additional tree clearing of approximately 5.9 acres along a separate ROW (Exh. HO-RR-J-8, at 2).

217 The Companies indicated that although use of the alternative route would require a second substation on the ROW, including a permanent access road, the ROW width would be significantly narrower along most of the alternative route's 0.9-mile length, thus reducing the acreage of tree-clearing needed (Exhs. BLK-BEC-14, at 1-10 to 1-12, 5-10; HO-J-R-1, at 2).

218 The Companies indicated that they would be able to plant more trees under the alternative route than under the primary route because the primary route would use more on-site area for transmission facilities that would otherwise be available for tree planting (Exh. HO-RR-J-8, at 3).

The Companies stated that there would be no impacts to endangered, threatened, or special animal or plant species resulting from construction of the proposed transmission lines along the alternative route (id. at 5-9). The Companies indicated that no significant historical or archaeological resources were identified by the Massachusetts Historical Commission in the immediate vicinity of the alternative route (Exh. BLK-BEC-16).

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 known rare or endangered species would be adversely affected by the proposed construction.

The record demonstrates that use of the alternative route would require the clearing of 15 fewer acres of trees than would the primary route, and that ANP would be able to plant six additional acres of trees to offset the tree clearing impacts associated with the siting of the proposed facilities. Given these differences in tree clearing, as well as the relatively low probability of adverse impacts resulting from directional drilling, the alternative route provides significant land resource advantages over the primary route. Consequently, the Siting Board finds that the alternative route would be preferable to the primary route with respect to land resources.

(3) Land Use

The Companies stated that land uses along the alternative route include commercial sand and gravel excavation at the southern portion of the project site, the Mill River and associated wetlands at the western end of the on-site portion of the route, and residential properties for the entire off-site portion of the route (Exh. BLK-BEC-14, at 5-11).[219] With respect to the residential portion of the alternative route, the Companies stated that

[219] The Companies stated that the proposed transmission lines would be located beneath public streets for 64 percent of the alternative route's length, or 0.58 miles (Exh. BLK-BEC-14, at 5-11).

construction activities would occur along the entire length of Spruce Street,[220] and at a crossing of Blackstone Street (id. at 5-19). The Companies explained that construction of the transmission lines would occur in two stages -- the placement of the manholes and steel pipes, and the installation of cables (id.). The Companies stated that construction of the substation within ROW 13 would occur outside of public roadways, but require access for equipment and materials during a nine month construction period (id. at 5-17, 5-19). The Companies indicated that the substation at the generating plant switchyard would be accessed via the plant site itself, thereby minimizing construction impacts (id. at 1-12). The Companies described possible traffic impact mitigation measures that would be implemented to alleviate associated impacts to the community, including restrictions on construction during peak hours and use of steel plates to maintain access to driveways and intersections (id.).

The Companies stated that noise related to the construction of the ROW substation would be audible beyond the ROW boundary and at nearby residences during the nine-month construction period (id.). However, the Companies added that mitigation measures such as compliance with Federal regulations limiting truck noise and use of sound-muffling devices on construction equipment would be implemented to reduce noise impacts (id. at 5-18).

The record demonstrates that some portion of the construction of the proposed facilities along the alternative route, unlike the primary route, would take place in residential areas, thus magnifying land use and noise impacts during the construction period. The record also demonstrates that construction along and across the affected streets under the alternative route would result in greater impacts to local traffic than are anticipated along the primary route. Finally, the record shows that construction of the second substation on ROW 13 -- required for the alternative route but not the primary route -- could contribute to greater overall noise and traffic impacts to the surrounding area. Thus, construction of the alternative route, although slightly shorter than the primary route, would likely generate significantly more land use impacts.

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220 The Companies explained that construction along Spruce Street would occur on just one side of the street in order to maintain one lane of traffic (Exh. BLK-BEC-14, at 5-19).

Accordingly, the Siting Board finds that the primary route would be preferable to the alternative route with respect to land use impacts.

(4) Visual Impacts

The Companies indicated that the alternative route would run overhead for approximately 1,000 feet from the proposed generating facility switchyard to a point near the Mill River (Exh. BLK-BEC-14, at 1-10). At this point, the transmission lines would transition to and remain underground until they reached the new substation on ROW 13 (id. at 1-10, 1-12). The Companies noted that the new substation is not required for the proposed facilities along the primary route (id. at 1-7, 1-12).

The Companies stated that there would be incremental visual impacts associated with the overhead portion of the interconnect due to the planned use of steel support structures for the lines within the generating plant site (id. at 5-12). However, the Companies argued that the transmission line supports would be visible primarily from locations that also have views of the upper sections of plant stacks (id.). The Companies also stated that limited views of the upper portions of the second substation located within the ROW would be possible in the surrounding area (id. at 5-14). The Companies indicated that, because the substation would be installed within ROW 13, Line 336 transmission structures spanning the substation site would be raised to a height of approximately 100 feet to provide necessary clearances. The Companies provided viewshed analysis of the ROW 13 substation site, with and without the proposed alternative route facilities, as seen from nearby residential areas on the west side of Blackstone Street (id. at Fig. 5-4).[221] The Companies added that no adverse visual impact to

221 The viewshed indicates roadside trees provide partial screening from Blackstone Road; however, the potential for views from residential property is indicated (Exh. BLK-BEC-14).

the surrounding community is expected from the underground portion of the route once construction is completed (id. at 5-12).[222,223]

The record demonstrates that although the alternative route is closer to residences than the primary route, the permanent visual impacts of the transmission lines at these residences would be considerably mitigated by burying the lines for most of the route. The record also demonstrates that the overhead portion of the alternative route would be located within 1,000 feet of the generating facility, isolated from residential areas, thereby minimizing its incremental visual impacts. However, the alternative route requires an additional substation on the ROW and taller overhead steel supports at the plant site. The Siting Board concludes that the visual impacts of the additional substation and taller supports offset the benefit of running a portion of the alternative route underground.

Accordingly, the Siting Board finds that the primary route and the alternative route would be comparable with respect to visual impacts.

(5) Magnetic Field Levels

The Companies provided magnetic field levels for both the overhead and underground portions of the proposed facilities along the alternative route (Exh. BLK-BEC-18). With respect to the overhead portion that extends from the plant switchyard, the Companies indicated that the magnetic field levels would be approximately 25 mG at a distance of 50 feet either side of center, directly beneath the lines (id.). The Companies estimated that the maximum magnetic fields for the directional drilled and trenched segments of the alternative

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222 The Companies explained that following the transition from overhead to underground, the underground facilities would be located beneath the Mill River, wetlands, and woodlands via directional drilling methods, and located beneath Spruce and Blackstone Streets and up to the ROW substation via trench methods (Exh. BLK-BEC-14, at 1-10, 5-12).

223 The Companies indicated that the closest residence to the proposed facilities along the alternative route would be located on Spruce Street at a distance of approximately 54 feet from the centerline (Exh. HO-RR-J-3.2, att.).

route would be 0.2 mG and 3.7 mG, respectively (id.). The Companies' witness, Dr. Bailey, testified that the magnetic field levels on the western, or closest, edge of Spruce Street would be 1.5 mG (Tr. 2, at 113-115). The Companies indicated that a negligible magnetic field level of under 0.1 mG would occur at the residence closest to the underground transmission lines beneath Spruce Street (id. at 114-115; Exh. HO-RR-J-3.2).

The record demonstrates that the proposed facilities along the alternative route would be underground in residential areas, thereby reducing magnetic field levels to well below 1 mG at the nearest residence along Spruce Street. Although the alternative route runs closer to residences than the primary route, the burying of transmission lines along most of the alternative route would reduce field levels to essentially unmeasurable levels at the closest residences, comparable to levels at the closest residences to the primary route.

Accordingly, the Siting Board finds that the alternative route would be comparable to the primary route with respect to magnetic field impacts.

(6) Conclusions on Environmental Impacts

In Sections IV.D.3. and 4, 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, and comparable with respect to visual impacts and magnetic field impacts. In addition, the Siting Board has found that the alternative route would be preferable to the primary route with respect to land resource impacts. On balance, 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 environmental impacts.

b. Cost of the Proposed Facilities along the Alternative Route and Comparison

The Companies estimated that the installation of the proposed transmission lines and associated facilities along the alternative route would cost $16.9 million, or $6.4 million more than along the primary route (Exh. BLK-BEC-14, at 4-21). The Companies explained that the increased costs under the alternative route are chiefly attributable to the cost of the additional substation on the ROW, redundant switching apparatus at the plant switchyard, and the higher cost of the underground transmission lines (id. at 5-20). Thus, the Companies concluded that the estimated total cost of the proposed facilities along the alternative route would be 61 percent greater than the estimated total cost of the proposed facilities along the primary route (id.).

Consequently, the Siting Board finds that the primary route would be preferable to the alternative route with respect to cost.

c. Conclusions

In comparing the proposed facilities along the primary and alternative routes, the Siting Board has found that the primary route would be preferable with respect to both environmental impacts and cost.

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 reliable energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

V. DECISION

A. The Generating Facility

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 generating 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 conditions listed in Section II.C, 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, traffic, and EMF, 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 pertaining 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 Blackstone Energy Company to construct a 580 MW bulk generating facility and ancillary facilities in Blackstone, Massachusetts subject to the following condition:

(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 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 BECo providing the proposed project with access to the regional transmission system.

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 this condition. The Company will not receive final approval of the proposed generating facility until it complies with this condition.

In addition, the Company shall comply with the following conditions during construction and operation of the proposed generating facility:

(B) In order to mitigate CO_2 emissions, the Siting Board requires ANP to provide CO_2 offsets through a total contribution of $620,691, to be paid in five annual installments during the first five years of facility operation, plus a contribution of $34,560 in the first year of facility operation as an offset for tree clearing to construct the gas and electrical interconnects, 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 $549,298 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 Blackstone 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 generating facility and related facilities at affected residential properties and at roadways and 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, 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 Blackstone and Mendon, and to all potentially affected property owners in those communities 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 minimize traffic related impacts, the Siting Board directs ANP to work with MHD and the Towns of Bellingham and Blackstone to develop and implement a traffic mitigation plan which addresses scheduling and roadway and bridge construction or improvement.[224] This plan should include, to the extent practicable, scheduling of 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. The plan 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.

(F) 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.

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224 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.

B. The Transmission Facilities

______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 reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. G.L. c. 164, § 69H.[225] 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.[226]

In Section IV.A, above, the Siting Board has found that the Companies have established a need for the proposed transmission facilities. Further, in Section IV.B, above, the Siting Board has found that the proposed facilities are preferable to the double radial alternative with respect to providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section IV.C, above, the Siting Board has found that the Companies examined a reasonable range of practical siting alternatives.

In Section IV.D, above, the Siting Board has found that the proposed transmission facilities along the primary route, with wooden H-frame structures, would achieve an appropriate balance among conflicting environmental concerns as well as among environmental impacts and cost.

In Section IV.D, 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 providing a reliable energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Board finds that, with compliance by ANP with the conditions set forth in Sections V.(B)and V.(D), above, the construction and operation of the proposed

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225 As amended by St. 1997, c. 164, § 204.

226 As amended by St. 1997, c. 164, § 209.

transmission facilities will provide a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In Section IV.D, above, the Siting Board has reviewed various environmental impacts of the proposed transmission facilities in light of related regulatory or other programs of the Commonwealth, including programs relating to wetlands protection, rare and endangered species, and historical preservation. As evidenced by the above discussions and analyses, the proposed facilities will be generally consistent with identified requirements under all such programs.

Accordingly, the Siting Board APPROVES the petition of ANP Blackstone Energy Company and Boston Edison Company to construct two 1.1 mile 345 kV overhead transmission lines in the Towns of Mendon and Blackstone, Massachusetts.

Because issues addressed in this Decision relative to these facilities are subject to change over time, construction of the proposed transmission lines 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 facilities in conformance with all aspects of its proposal as presented to the Siting Board. Therefore, the Siting Board requires the Companies 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 Companies are 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
Hearing Officer

Dated this 14th day of January, 1999

APPROVED by the Energy Facilities Siting Board at its meeting of January 13, 1999 by the members and designees present and voting: Sonia Hamel (Acting Chair, for Robert Durand, Secretary of Environmental Affairs); W. Robert Keating (Commissioner, DTE); James Connelly (Commissioner, DTE); and David L. O'Connor (for Carolyn Boviard, Director of Economic Development).

Sonia Hamel, Acting 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).