DECISIONS AND ORDERS

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FACILITIES SITING COUNCIL

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Northeast Utilities for Approval of its 1986 Long-Range Forecast of Electrical Loads and Power Facilities, and its 1987 Supplement to that Forecast	EFSC 86-17

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:

Michael P. Aronson

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The Energy Facilities Siting Council hereby APPROVES the 1986 and 1987 Demand Forecasts and Supply Plans of Northeast Utilities.

I. INTRODUCTION

A. Description of the Company

The Western Massachusetts Electric Company ("WMECO"), the Holyoke Water Power Company ("HWP"), and the Holyoke Power and Electric Company ("HP&E") are subsidiaries of the Northeast Utilities System ("NU" or "Company"). NU, the largest electric utility in New England, is a public utility holding company comprising the Connecticut Light and Power Company ("CL&P"), WMECO, HWP, HP&E, and the Northeast Nuclear Energy Company. Its Massachusetts subsidiaries, WMECO, HP&E, and HWP, are subject to Siting Council jurisdiction. In 1986, NU experienced a peak demand of 4353 MW and sold approximately 22,500 gigawatt-hours of electricity to about 1.06 million customers (Exh. HO-1, pp. 7, 9, 23).

WMECO produces, sells, and distributes electricity to approximately 172,000 retail customers in Western Massachusetts. In 1986, WMECO sold approximately 3,905,000 megawatt-hours ("MWH"), with a winter peak of 681 megawatts ("MW") (id., pp. II-39 - II-47). WMECO sold 32.5 percent of its energy to the residential class, 28.6 percent to commercial customers, and 26.7 percent to industrial customers (id., p. II-46).

HWP produces, sells, and distributes electricity to two customer classes: industrial and wholesale for resale (id., p. II-5). HWP's wholesale customers include HP&E and the City of Chicopee Electric Department. In 1986, HWP sold approximately 333,000 MWH, with a summer peak load of 62 MW (id., pp. II-11 - II-12).

HP&E is a subsidiary of HWP. HWP is considered to be the owner of all facilities owned directly or through HP&E (id., p. iv), and therefore its statistics include both HP&E and HWP. HP&E sells wholesale power to the South Hadley Electric Light Department, and provides transmission services for owners of power entitlements in the Mt. Tom power plant including WMECO, HWP, and the New England Power

Company (id., p. II-5).

Together WMECO and HWP had retail sales in 1986 of 4,238,000 MWH, with a non-coincident peak demand of 731 MW, representing 17 percent of NU's 1986 peak load (id., pp. II-81 - II-82).

B. Procedural History

On April 1, 1986, the Company filed its 1986 demand forecast and supply plan (Exhs. HO-3, HO-4). On September 10, 1986, the Hearing Officer issued a Notice of Adjudication and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company subsequently submitted confirmation of publication.

On March 31, 1987, the Company filed its 1987 demand forecast and supply plan (Exhs. HO-1, HO-2). On April 24, 1987, the Hearing Officer issued a Notice of Adjudication which stated that the reviews of the Company's 1986 and 1987 demand forecasts and supply plans would be consolidated. On May 27, 1988, pursuant to the directions of the Hearing Officer, the Company filed confirmation of publication and posting.

Evidentiary hearings were held on January 26 and January 28, 1988. The Company presented four witnesses at the hearings: Bruce G. Blakey, manager of economic and load forecasting; John Hagerty, economic and load forecasting analyst; William Stillinger, director of system planning; and Michael W. Townsley, manager of demand program planning and analysis. The Energy Facilities Siting Council ("Siting Council" or "EFSC") entered 115 exhibits in the record, largely composed of the Company's responses to information and record requests.[1] NU offered 11 exhibits into the record.

1/ On April 7, 1988, the Hearing Officer issued ten additional record requests and informed the Company that, if the Company had no objections, responses to these requests would be entered into the record. The Company filed no objection. These responses were entered as Exhibits HO-IDSP-10, HO-IDSP-11, HO-IDSP-12, HO-IDSP-13, HO-IDSP-14, HO-IDSP-15, HO-12.A, HO-12.B, HO-13.A, HO-13.B, HO-14 and HO-15.

II. ANALYSIS OF THE DEMAND FORECAST

A. Standard of Review

As part of its statutory mandate "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, sec. 69H, the Siting Council determines whether "projections of the demand for electric power...are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. To ensure that the foregoing standard is met, the Siting Council applies three criteria to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if it contains enough information to allow full understanding of the forecasting methodology. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility that produced it. A forecast is reliable if the methodology provides a measure of confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. Boston Edison Company, 15 DOMSC 287, 294 (1987).

B. Previous Demand Forecast Conditions

In Northeast Utilities, 11 DOMSC 1 (1984), the Siting Council approved NU's demand forecast subject to five conditions:[2]

1. That forecast documentation be expanded to comply with Siting Council regulations 980 CMR 7.03(5) and 980 CMR 7.09(3)

2. That the Company re-evaluate its short-term housing stock model and further substantiate the basis for deriving customer and employment forecasts from state-wide forecasts.

3. That the Company explicitly incorporate price effects into the Companies' long-run forecasting models and suitably document them.

2/ The numbers preceding each condition correspond to the numbers assigned in the 1984 decision.

4. That the results of the Company's experiment with forecasting industrial sales on a disaggregated basis, as well as its study of conservation, technological change, and building standards assumptions, be submitted with the Company's next filing.

5. That potential energy and/or capacity credits from contracts with the Power Authority of the State of New York ("PASNY"), Hydro Quebec, and other predictable exchanges of energy and capacity be appropriately reflected in the electric price forecast.

Compliance with these conditions is discussed in Sections II.D.1 through II.D.6, <u>infra</u>.

C. <u>Demand Forecast Results</u>

For WMECO and HWP combined, the Company projected total energy requirements to grow at 0.9 percent per year over the forecast period. Aggregate growth rates are a composite of the growth rates in the residential, commercial, industrial, streetlighting, railroad, and wholesale for resale classes (Exh. HO-1, p. I-2). NU projected compound annual growth rates for its Massachusetts subsidiaries of 0.8 percent in the residential class, 0.4 percent in the commercial class, 1.2 percent in the industrial class, and 1.8 percent in the wholesale for resale class (<u>id</u>., pp. II-74 - II-82). Sales in the streetlighting class were projected to decline at an annual rate of 1.4 percent (<u>id</u>.).

For the system as a whole, NU expects higher growth rates, at 2.3 percent annually for electricity sales between 1986 and 1996. The Company projected growth rates of 1.9 percent in the residential class, 3.2 percent in the commercial class, 2.0 percent in the industrial class, and 0.5 percent in the wholesale for resale class (<u>id</u>., p. 7). Sales in the streetlighting class are projected to decline at an annual rate of 2.3 percent (<u>id</u>.).

For its Massachusetts subsidiaries, NU projected an annual growth rate in peak demands of 0.9 percent over the forecast period (<u>id</u>., p. II-82), as compared to a peak load growth rate of 1.9 percent for the entire system. Therefore, NU estimated peak load growth for the Massachusetts subsidiaries to be substantially lower than that of its

Connecticut subsidiaries (id., p. 8).

The demand forecast results are contained in Table 1.

D. Forecast Methodology

NU developed its demand forecast through a set of integrated methodologies. As inputs to its models in different customer classes, NU developed forecasts of the economic and demographic trends in its service territory, along with projections of the real price of electricity. The Company's 1986 and 1987 demand forecast methodologies were similar; hence, the Siting Council focuses its review on the 1987 demand forecast.

1. Economic and Demographic Forecast

In Condition Two of the Siting Council's most recent decision, the Siting Council ordered the Company to re-evaluate its short-term housing stock model and further substantiate the basis for deriving customer and employment forecasts. In this proceeding, the Company submitted economic and demographic models created for NU by Data Resources Incorporated ("DRI") to forecast the demographic attributes of the WMECO service territiory (Exh. HO-I-5). In these models, DRI estimated housing stocks, customer base, and future economic trends using certain theoretical assumptions and reliable data.[3] Accordingly, the Siting Council finds that the Company has complied with Condition Two of the Siting Council's last decision. Further, the Siting Council finds that the Company's economic and demographic forecast is reviewable, appropriate, and reliable.

3/ NU uses the DRI economic and demographic models to provide inputs for various sub-models of the demand forecast. Information derived from the DRI economic and demographic forecast includes the level of economic activity in the WMECO service area, levels of employment in various sectors of the economy, and the number of residential electricity customers.

2. Electricity Price Forecast

NU projected the real price of electricity using a financial model that simulates NU's system operations. The Company determined the real price of electricity as a function of the 1986 forecast for system peak demand and energy output, results from the Integrated Demand/Supply Planning ("IDSP") process, fossil-fuel price projections provided by DRI, internally generated nuclear fuel costs, and certain engineering and financial data (Exh. HO-D-13, pp. 1-6).

In Condition Five of its last decision, the Siting Council ordered NU to incorporate the effects of Hydro-Quebec, PASNY, and other predictable exchanges of energy and capacity into the electricity price forecast. In this proceeding, the Company filed its Average Price of Electricity Forecast which incorporated the effects of Hydro-Quebec, PASNY, and other exchanges of energy and capacity (Exh. HO-D-13). Accordingly, the Siting Council finds that the Company has complied with Condition Five of its last decision.

Further, the Siting Council finds that the Company's electricity price forecast is reviewable, appropriate, and reliable.

3. Short-Run Demand Forecast

NU defined its short-run demand forecast period as one year, and developed a short range model to forecast energy requirements and hourly load for the first year of the Company's ten-year forecast period (Tr. I, p. 26). The Company estimated the NU system's 1988 energy consumption using an econometric model. Model inputs included economic and demographic data, electricity price, and industry estimates of electricity consumption. Using a statistical hourly load model, NU estimated 1988 peak loads and monthly energy output by company and by customer class (Exh. HO-1, p. 21; Exh. HO-D-1.b). As the Company states, "an econometric model measures the historic relationships between a dependent variable ... and causative factors" (Exh. HO-1, p. I-6). The Siting Council finds that these historic relationships are valuable for short-run trend estimation, and that the Company's short-run forecast is reviewable, appropriate, and reliable.

4. Long-Run Forecast

a. Residential Forecast

i. Description

NU predicted total residential electricity consumption with econometric and end-use models. These models relied on inputs from the economic and demographic forecast, the average price of electricity forecast, and various databases. NU determined the first year of the long-run forecast with the short-run model (see Section II.D.3, *supra*), and used the elasticities estimated in the short-run model to modify the long-run forecast (Exh. HO-1, p. 22).

The NU end-use model assumed residential consumption is a function of the consumption of 16 household appliances[4] and a miscellaneous component. Data required for the end-use model includes the number of each appliance in use, average electricity use per appliance, and the intensity of appliance use (i.e., average number of hours of use per appliance per year). Future residential electricity consumption depends upon new appliance penetrations, appliance retirements, and the intensity of appliance use (*id*., p. 32).

Since residential customers are the users of appliances, the Company chose the number of residential customers as the key driving variable in the residential end-use model (*id*.). NU forecasted the number of residential customers on the WMECO system using two regression equations (Exh. HO-I-5, p. 7).

NU estimated the number of residential appliances from three sources. For electric heating appliances, NU used Company records to identify customers that rely on electric heat for a significant

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4/ These 16 household appliances include electric space-heating system; electric heat pump system; electric-assisted renewable resource space heating; electric water heating; electric-assisted renewable resource water heating system; fossil fuel heating auxiliaries; central air conditioning; room air conditioning; electric range; electric dryer; manual defrosting refrigerators; automatic defrosting refrigerators; freezer; color television; lighting; and electric car (Exh. HO-1, p. 31).

percentage of their space heat. Using a 1982 saturation survey of all-electric customers, NU separated these consumers into electric space heating, heat pump, and electrically assisted renewable resource space heating categories. A 1983 NU appliance saturation survey, which established ownership percentages of appliances by building type, generated an estimate of the number of residential appliances in use (Exh. HO-1, p. 34).

For each year of the forecast, NU determined the number of new residential appliances in the market by applying market penetration percentages to the new housing, replacement housing, and existing market categories (id.).

The Company determined the electricity use of an appliance type in each year by calculating the product of the number of appliances, the average kilowatt use per appliance, and the intensity of use (Exh. HO-1, p. 36). The results of this algorithm summed over all appliance types, determined the aggregate residential appliance energy consumption (id., p. 36).

The Company forecasted a reduction in electricity consumption by individual appliances due to rising energy costs, voluntary efficiency standards adopted by the construction and appliance manufacturing industries, increasing awareness of cost effective conservation measures, and long-run price effects. However, the Company projected an increase in aggregate consumption of electricity by residential appliances over the forecast period due to an increase in personal income, an increase in saturations of appliances, a shift toward larger appliances, and more intensive use of residential appliances (Tr. I, pp. 40-42).

ii. Analysis

In Condition Three of its last decision, the Siting Council ordered the Company to incorporate price effects into its long-run forecasting models. In this proceeding, the Company has shown that price effects have been incorporated into its appliance usage component of the residential forecast. Accordingly, the Siting Council finds that the Company has complied with Condition Three of its last decision with regard to the residential class forecast.

In past decisions the Siting Council has accepted the use of end-use modeling methodologies for forecasting residential class consumption. Massachusetts Electric Company, 12 DOMSC 197, 202-213 (1985); Boston Edison Company, 10 DOMSC 203, 218 (1984). In this case, the Company's use of end-use methodology allows it to accurately project residential class consumption. Accordingly, based on the record in this proceeding, the Siting Council finds that the Company's residential forecast is reviewable, appropriate, and reliable.

b. Commercial Forecast

NU projected commercial class demand with econometric and end-use models. The Company employed an updated version of the commercial end-use model that it used in its previous forecast. For the current forecast, the Company used the same end uses and a more highly disaggregated building-type database (see Section II.D.4.b.i, infra). Underlying NU's use of these models are three major assumptions: (1) that new commercial buildings use over 30 percent more electricity than the existing building stock per square foot; (2) that employment growth is a proxy for commercial floor space growth; and (3) that the NU electricity price forecast is reliable (Exh. HO-1, pp. 53, 55).

i. The End-Use Model

For the end-use model, NU disaggregated the commercial class into ten building types and four end uses.[5] The Company created two categories of consumption for the commercial class: (1) sales to existing building stock, and (2) sales to new construction stock. An NU survey completed in 1983 provided base year data on the square footage

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5/ The ten building types are offices, restaurants, retail stores, food stores, warehouses, elementary and secondary schools, colleges and trade schools, health care facilities, hotels and motels, and miscellaneous (Exh. HO-1, p. 54). The four end uses are space heating, cooling, lighting, and "other" (id.).

of each market. In each year of the 1987 demand forecast, the square foot area of existing building stock and new construction stock are changed to reflect building demolitions and the addition of new commercial floor space. In its model, the Company assumed employment growth determines the demand for commercial floor space and therefore used it as a proxy for floor space growth (Exh. HO-1, p. 51).

NU studied total energy requirements per square foot for each commercial building type and for each end use (id., p. 52). The Company adjusted its estimates of the electric component of the energy requirements per square foot with econometrically derived price and employment elasticities (see Section II.D.4.b.ii, infra).

The model adjusted electricity sales for non-price induced conservation and cogeneration by incorporating governmental efficiency standards, NU conservation programs, and other influences (Exh. HO-1, p. 53).

ii. The Econometric Model

NU adjusted estimates of the electric energy requirements for the commercial class over time with price and employment elasticities generated in an econometric model (Exh. HO-1, p. 53). In the model, the Company estimated electricity use as a function of (1) a three-year moving average of employment lagged one period; (2) the price of electricity; (3) the previous period's electric sales; and (4) a dummy variable to capture the effects of oil price increases in 1979 (Exh. HO-1, p. 55). NU used the employment and price elasticities generated in the regression to adjust estimates of electric energy requirements in the end-use model. The Company assumed that the employment elasticities indicate how trends in employment affect the penetration of electric appliances in the commercial market, and that price elasticities indicate how the price of electricity affects the efficiency of commercial appliances (id.).

iii. Analysis

In past reviews of commercial forecasts, the Siting Council has required electric companies to support their assumptions regarding growth rates in commercial floorspace. Massachusetts Electric Company, 12 DOMSC 197, 220-221 (1985); Boston Edison Company, 10 DOMSC 203, 225-232 (1984). In Massachusetts Electric Company, 12 DOMSC 197, 220-221 (1985), the Siting Council directed the companies to reevaluate the use of major simplifying assumptions, such as the assumption of constant levels of square footage per employee over the forecast period. In Boston Edison Company, 10 DOMSC 203, 225-232 (1984), the Siting Council accepted Boston Edison's end-use commercial class forecast methodology, but urged the company to estimate the sensitivity of the model to changes in the assumed growth rate in commercial building space.

In the instant case, the Company's witness, Mr. Blakey, argued that employment growth is a proxy for the growth in commercial floorspace, and that "the conversion of employment to square footage is really multiplication" (Tr. I, p. 57). The Company also asserted that it obtained employment data from federal and state sources because that data is "reliable and inexpensive" (Exh. HO-1, p. 51; Tr. I, p. 56).

The Company also argued that more direct and reliable information on commercial floorspace is not available. Still, the Company's subcontractor, Synergic Resources Corporation ("SRC"), has used direct data on commercial buildings provided by F.W. Dodge, a division of McGraw Hill (Exh. HO-I-8.B, pp. ES-2, I-4).[6] Mr. Blakey stated, however, that the F.W. Dodge data is more applicable to analysis of specific building projects (Tr. I. pp. 54-55).

In this case, the Company has failed to establish that a linear relationship exists between employment growth and the growth in commercial floorspace over time. NU's use of employment as a proxy for commercial floorspace fails to consider other economic factors that may have an impact on commercial floorspace growth, including the costs of construction, real estate, and labor.

The Siting Council finds that the Company has not adequately

6/ The record indicates that SRC used the F.W. Dodge data for new office building energy surveys.

examined other data sources for its commercial model. While the Company has argued that direct commercial floorspace data are more expensive and less reliable, it failed to present any analyses of costs or reliability for either method of projecting commercial floorspace growth. For a Company of NU's size and resources, the Siting Council requires a showing that employment statistics represent the best available data for predicting commercial floorspace growth. Accordingly, the Siting Council finds that the Company has failed to establish that its use of employment growth as a proxy for the growth in commercial floorspace is appropriate or reliable.

iv. Conclusions on the Commercial Forecast

In Condition Three of its last decision, the Siting Council ordered the Company to incorporate price effects into the Company's long-run forecasting models. In this proceeding, the Company demonstrated that price effects have been incorporated into the commercial class model with price elasticities generated in an econometric model for the commercial class. Accordingly, the Siting Council finds that the Company has complied with Condition Three of its last decision with regard to the commercial class forecast.

The Siting Council has found that the Company has failed to establish that its use of employment growth as a proxy for the growth in commercial floorspace is appropriate or reliable. Accordingly, while the Siting Council finds that the Company's commercial forecast is minimally reviewable,[7] the Siting Council also finds that the Company has failed to establish the its commercial forecast is appropriate or reliable.

The Siting Council ORDERS the Company to present in its next

7/ The Siting Council notes that in this proceeding the Company has presented its commercial forecast in a piecemeal and highly generalized manner. Specifically, the Company has not provided clear descriptions of various model components. In preparing its next filing, the Company is reminded of its responsibility to present the commercial forecast in a reviewable manner.

forecast filing an analysis of each of the economic factors which may have an impact upon commercial floorspace growth.

c. Industrial Forecast

i. Description

NU forecasted industrial consumption using an econometric model. The Company expressed WMECO industrial class electricity consumption as a function of the previous year's consumption by the industrial class, the real price of electricity, and an index of industrial production (Exh. HO-1, p. 62).

ii. Analysis

In its last decision, the Siting Council criticized the Company's use of the industrial production index as a determining variable in the Company's industrial class econometric model. Northeast Utilities, 11 DOMSC 1, 12 (1984). In the instant case, the Company has failed to sufficiently document the industrial production index as a determinant of industrial electricity consumption. Additionally, the Company has failed to describe the theoretical basis for its non-linear model structure in sufficient detail.

Accordingly, the Siting Council ORDERS the Company to file in its next forecast, supporting documentation describing (1) each of the variables used in the industrial class econometric model, and (2) the theoretical basis for using non-linear estimation in the industrial class model.

In past decisions, the Siting Council has encouraged the incorporation of electricity price into the group of determining variables for industrial class econometric models. Massachusetts Electric Company, 12 DOMSC 197, 222-224 (1985); Boston Edison Company, 10 DOMSC 203, 230-239 (1984). In Condition Three of its last decision, the Siting Council ordered the Company to incorporate price effects into the Company's long-run forecasting models. In the instant case, the Company explicitly incorporates price into its econometric models.

Accordingly, the Siting Council finds that the Company has complied with Condition Three of its last decision with regard to the industrial forecast.

In Condition Four of the Siting Council's last decision, the Siting Council ordered NU to submit the results of the Company's experiment with forecasting industrial sales on a disaggregated basis, as well as its study of conservation, technological change, and building standards. In this proceeding, the Company submitted an addendum to its forecast which includes the information required by the Siting Council (Exh. NU-3). Accordingly, the Siting Council finds that the Company has complied with Condition Four of its last decision.

Based on the record in this proceeding, the Siting Council finds that, on balance, the Company's industrial forecast is reviewable, appropriate, and reliable.

d. Peak Load Forecast

To calculate peak loads, NU developed an hourly load model based on the EPRI Hourly Electric Load Model ("HELM") and NU data (Exh. HO-1, p. 95). Data used for this model included (1) annual sales forecasts, (2) minutes of darkness per hour for each hour of the year, (3) heating/cooling degree hours, (4) monthly and daily shares of consumption for non-temperature sensitive consumers and appliances, (5) a calendar to identify day types, (6) hourly temperatures for a normal year, and (7) system losses and internal use (Exh. HO-D-1.B, p. 3).

Based on the record in this proceeding, the Siting Council finds that NU's peak load forecast methodology is reviewable, appropriate, and reliable.

E. Conclusions on the Demand Forecast

The Siting Council has found that the Company has complied with Conditions One through Four of its last decision, and Condition Five of its last decision with regard to the electricity price forecast.

The Siting Council has also found that (1) the Company's economic and demographic forecast, electricity price forecast, residential forecast, industrial forecast, and peak demand forecast are reviewable, appropriate, and reliable, (2) the Company's commercial forecast is reviewable, and (3) the Company has failed to establish that its commercial forecast is appropriate or reliable.

Accordingly, the Siting Council finds that, on balance, the Company's 1986 and 1987 demand forecasts are reviewable, appropriate, and reliable.

The Siting Council hereby APPROVES the Company's 1986 and 1987 demand forecasts.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate "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, sec. 69H, the Siting Council reviews three dimensions of an electric utility's supply plan: adequacy, diversity, and cost.

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. Boston Edison Company, 15 DOMSC 287, 350 (1987). The Siting Council also evaluates whether a supply plan minimizes the cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Nantucket Electric Company, 15 DOMSC 363, 384-390 (1987). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. Boston Edison Company, 15 DOMSC 287, 339-349 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 136-138, 165-166 (1986). Finally, the Siting Council determines whether utilities treat all resources -- including demand management, conventional power plants, and purchases from cogeneration and small power projects and from other utility and non-utility suppliers -- on the same basis when attempting to develop an adequate, diverse and least-cost supply plan.[8] Boston Edison Company, 15 DOMSC

8/ In 1986, the Massachusetts Legislature amended the Siting Council's statute to require the Siting Council to approve a company's forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

287, 315-323 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 133-135, 151-155, 166 (1986).

Further, the Siting Council reviews the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council requires utilities to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's consistent and systematic application of such criteria to supply planning decisions indicates that a company is evaluating new supply options in a manner that ensures an adequate supply of least-cost, least-environmental-impact power. These processes and criteria take on added importance when the dynamic nature of the energy generation market and the inherent uncertainty of projections make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast. Nantucket Electric Company, 15 DOMSC 363, 378-379, 384, 390-391 (1987); Boston Edison Company, 15 DOMSC 287, 301, 322-323, 339-348 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 133-135 (1986); Fitchburg Gas and Electric Light Company, 13 DOMSC 85, 102 (1985).

The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company, 15 DOMSC 125, 134 (1986).

To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies should necessary projects not develop as originally planned. Boston Edison Company, 15 DOMSC 287, 309-322 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 134-135, 144-150, 165-166 (1986). The Siting Council has defined the short run as the period of time necessary to place into service sufficient resources obtainable from the shortest-lead-time resource option under a given company's control in a timely and cost-effective manner. The short run may vary on a company-by-company basis. Boston Edison Company, 15 DOMSC 287, 297, 307-308 (1987).

To establish adequacy in the long run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of supply options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisions to ensure adequate, cost-effective energy and power resources over all forecast years. The Siting Council recognizes that the later years of the forecast may offer new, but as yet unknown, resource options which are both reliable and cost-effective. The potential for these new resource options should increase in an electric generation and transmission market that adapts to a higher degree of uncertainty, becomes more competitive, and spawns projects which have shorter lead times. In formulating its standard for adequacy in the long run, the Siting Council recognizes this new energy environment and affords companies the opportunity to plan for their supplies in a creative and dynamic manner. Id., pp. 298, 313-320.

B. Compliance with Previous Supply Plan Conditions

In Northeast Utilities, 11 DOMSC 1 (1984), the Siting Council approved the Company's 1983 supply plan subject to two conditions:

5. That potential energy and/or capacity credits from contracts with the Power Authority of the State of New York ("PASNY"), Hydro Quebec, and other predictable exchanges of energy and capacity be appropriately reflected in planning models.

6. That NU shall refine its cost/benefit analysis to: account for the appropriate "average cost" at the margin; substantiate and document the kilowatthour savings for each program; and to reflect any capacity, transmission, and distribution effects of conservation.

In response to Condition Five, the Company has incorporated contracts with PASNY, Hydro-Quebec, and other predictable exchanges of capacity into its supply plan (Exh. HO-2, Table E-17). Accordingly, the Siting Council finds that NU has complied with Condition Five of its last decision with regard to its supply plan.

In Condition Six, the Siting Council required NU to refine its cost/benefit analysis for C&LM programs. In filing the "WMECO Determination of Long-Run Avoided Costs" (Exh. HO-I-4.A), and by accounting for the beneficial effects of C&LM programs by adding an appropriate percentage to the aggregate savings attributed to those programs, the Siting Council finds that Company has complied with Condition Six of the last decision.

C. Supply Planning Process - Overview

NU used its IDSP process to develop its supply plan. NU designed the IDSP process as a flexible planning tool to provide consistent evaluation of all supply options, and incorporate financial and public policy objectives in seeking the lowest cost energy supply for the long term (Exh. HO-I-1.A, p. i). The IDSP process is reviewed in Section III.E, infra.

Since the Company's 1986 and 1987 supply plans are similar, the Siting Council focuses its review on the 1987 supply plan.

D. Adequacy of the Supply Plan

1. Adequacy of Supply in the Short Run

a. Definition of the Short Run

A company's short-run planning period is defined as the time required for a company to place into service resources under its direct control in sufficient quantities to meet the projected need for new capacity. The short-run planning period varies on a company-by-company basis. NU asserted that its shortest-lead-time resource, a combustion turbine, would require a four- or five-year lead time to place into service (Exh. HO-6, p. 2; Tr. I, pp. 74-75).[10] Accordingly, the Siting Council finds that NU's short-run period would be five years, extending through the 1991 power year.

b. Base Case Supply Plan

NU estimated that its peakload and reserve requirements will grow at an annual rate of 2.6 percent per year between 1987 and 1996. The base case supply plan consists of (1) existing utility-owned generation and conservation and load management; (2) a four-percent entitlement in the Seabrook 1 nuclear plant; (3) purchases from cogenerators; (4) firm energy purchases from the Hydro-Quebec Phase II project; and (5) additions to hydroelectric capacity (Exh. HO-2, pp. III-5 - III-6; Exh. HO-1, p. 8). In the short run, the Company projects surplus capacity (see Table 2). Accordingly, the Siting Council finds that the Company's base case supply plan is adequate to meet requirements in the short run.

c. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must establish that it can meet its forecasted needs under a reasonable range of contingencies. To evaluate the adequacy of NU's short-run supply

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10/ In Commonwealth Electric Company, 15 DOMSC 125, 145 (1986), the Siting Council noted that in determining the short-run planning period, the Siting Council might use other time periods where the evidence indicates that lead times associated with other resource options -- such as power purchases from qualifying facilities, demand management, or baseload units -- should determine the threshold between the short-run and long-run planning horizons.

In this proceeding, the Company was required to provide an estimate of the time that would be needed to achieve 85 MW of C&LM supplied power (Exh. HO-10). The Company asserted that it could acquire 66 MW of C&LM "capacity" in five years, using two C&LM resource options (Exh. HO-10, Table 1). While the Siting Council has concerns about whether the Company's own estimates of capacity from C&LM could, in fact, be achieved in the allotted time period using the proposed programs, for the purpose of this review, the Siting Council accepts the Company's assertion. The Siting Council notes that, in future reviews, the short run may be defined on the basis of C&LM.

plan, the Siting Council analyzes three contingencies: (1) a high load growth scenario; (2) the cancellation or delay of Seabrook 1 nuclear plant beyond 1991; and (3) the double contingency of high load growth and the delay of the Seabrook 1 nuclear plant beyond 1991.

i. High Load Growth Scenario

Under the high load growth scenario, demand for electricity grows at 3.2 percent annually (Exh. HO-I-13, Exhibit RHB-3, p. 8). In this case, if all other resources in the base case plan remain intact, the Company would have sufficient capacity to meet its capability responsibility throughout the short run (see Table 3) (Exh. HO-11, Table 1). Hence, no additional resources would be needed to meet requirements within the short-run planning period. Accordingly, the Siting Council finds that the Company has established that it has adequate supplies to meet requirements in the short run in the event of high load growth.

ii. Cancellation or Delay of Seabrook 1

The Company expects the Seabrook 1 nuclear plant to contribute 47 MW toward NU's capability responsibility from April 1989 through the end of the forecast (Tr. I, p. 105). The Siting Council evaluates the adequacy of NU's short-run supply plan in the event that the Seabrook 1 nuclear plant is cancelled or delayed beyond the short run.

If the the Seabrook 1 nuclear plant is cancelled or delayed, NU would lose 47 MW of capacity for each year it is off-line (Exh. HO-1, p. III-27). Under this scenario, the Company would be able to meet its requirements without the addition of resources in the short run (see Table 3) (id.). Accordingly, the Siting Council finds that the Company has established that it has adequate supplies to meet requirements in the short run in the event that the Seabrook 1 nuclear plant is cancelled or delayed.

iii. Double Contingency of High Load Growth and Cancellation or Delay of Seabrook 1

The Siting Council evaluates the adequacy of NU's supply plan in the short run in the event of high load growth and the cancellation or delay of the Seabrook 1 nuclear plant. If these two events both occur, the Company would not experience supply deficiencies in the short run (see Table 3). Accordingly, the Siting Council finds that the Company has established that it has adequate supplies to meet requirements in the short run in the event of high load growth and the cancellation or delay of the Seabrook 1 nuclear plant.

2. Adequacy of Supply in the Long Run

The Company's long-run planning period is the remaining forecast horizon beyond the short run, from 1992 through 1996. Of these long-run forecast years, the Company's base case indicates that no deficiencies are expected to occur (Exh. HO-8).

As previously stated in Section III.A, supra, the Siting Council does not require electric companies to prove that they have adequate supplies in the later years of the forecast, provided the company demonstrates that its planning process can identify and fully evaluate a reasonable range of supply options. The ability of NU's supply planning process to identify and fully evaluate a reasonable range of supply options is fully discussed from the perspective of least-cost supply planning in Section III.E, infra. As indicated in Section III.E.3, infra, the Siting Council makes no finding regarding whether the Company's supply planning process identifies and fully evaluates a reasonable range of supply options.

3. Conclusions on the Adequacy of Supply

The Siting Council finds that NU's supply plan ensures adequate resources to meet projected aggregate system needs in the short run under a reasonable range of contingencies.

At the same time, however, the Siting Council makes no finding as to whether the Company's supply planning process identifies and fully evaluates a reasonable range of least-cost supply options in the long run.

E. Least-Cost Supply

1. Integrated Demand/Supply Planning Process

The Company stated that NU developed its IDSP process in 1983 to help corporate planners select appropriate stategies to meet forecasted demand (Exh. HO-I-1.A, p. i). The Company asserted that "the objective of the IDSP process is to select a balanced mix of reliable demand and supply resources that, over the long term, can be expected to keep electric rates at the lowest practical level" (Exh. HO-I-13, p. 3). NU asserted that the IDSP process will provide a consistent evaluation of all supply options (Exh. HO-1.A, p. i). Finally, the Company stated that using IDSP enabled the evaluation of all electricity supply alternatives on an equal footing and the subsequent selection of the least-cost mix of supply resources (id., p. V-9).

Basically, the IDSP process includes six steps: (1) developing an annual forecast of energy and peak demands; (2) screening generational and non-generational supply options; (3) ranking supply options on a consistent and comparable basis; (4) combining the options into alternative resource plans; (5) subjecting each alternative resource plan to economic and financial evaluation; and (6) subjecting selected resource plans to an uncertainty analysis (Exh. HO-I-1.A, p. ii). The results of the IDSP process determine the sequence of development for uncommitted capacity options (Exh. HO-D-13, p. 3).

a. Energy Output and Peak Demand Forecast

The annual forecast of energy output and peak demands under a variety of economic and demographic assumptions is described and reviewed in Section II, supra.

b. Screening of Supply Options

The Company used a screening process to select the most promising candidates from a comprehensive group of supply technologies for analysis in later stages of the IDSP process. For both generational and non-generational supply options, the screening process relied on "reasoned judgment" to determine which technologies fit best within the NU system (Exh. NU-6, p. 6). The screening processes for generational and non-generational supply options were independent.

i. Screening of Generational Supply Options

The Company used both technical and economic analyses to screen generational supply options. In its technical analysis, the Company evaluated 42 electric generation technologies[11] using four qualitative criteria: (1) availability of the primary fuel resource within the NU service territory; (2) availability of data about the technology's performance and cost; (3) ability to license the technology in the NU service territory; and (4) an assessment as to whether the technology will be commercially available so that it can be placed in service by 2005 (Exh. NU-6, p. 18). The Company used the results of the technical analysis to determine which technologies were viable in the NU service territory. On the basis of these four criteria, the Company eliminated technology categories judged inapplicable to the NU system from further IDSP analysis.

In the economic analysis, the Company selected specific generation plant "options" as examples of the acceptable technology categories for further analysis. To evaluate each option, NU used both estimated busbar costs and qualitative criteria (id., pp. 30-37). The Company stated that supply options in this stage of the screening

11/ In its technical analysis of generation projects, the Company refers to "generational technologies." Technologies that are not eliminated in the technical analysis are considered in the economic analysis in the form of specific "generational options" that are examples of "generational technologies."

process were generally accepted or rejected on the basis of their comparative busbar costs, but that qualitative characteristics were factored into the ranking process when busbar costs were similar (id., p. 37). The qualitative criteria included modularity of construction, desirable environmental characteristics, ease of fuel switching, fast response capability, and good heat rates at partial load (id.).

ii. Screening of Non-Generational Supply Options

NU screened 70 C&LM technologies. First, in a technical analysis, the Company evaluated each of the technologies using "Intuitive Selection," an analytical technique developed by the EPRI and the Edison Electric Institute ("EEI") (Exh. HO-I-14, p. 21). NU adapted the EPRI/EEI method to its own system, focusing the technical analysis on the 13 most important criteria for meeting NU's load shape objectives (id., pp. 21, 23).[12] The Company assigned C&LM technologies a numeric value for each of the selected criteria. The sum of these 13 values generated an overall technical value for each C&LM technology. The Company then ranked all the C&LM technologies by technical value. The Company stated that technical values represent a relative ranking only (id., pp. 25-26).[13]

In an economic analysis, the Company ranked C&LM technologies from the consumers perspective by calculating the internal rate of return ("IRR") for each option (id., p. 7). The Company stated that commercial customers will not volunteer to invest in a C&LM technology that provides less than a 50 percent IRR, and residential customers will

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12/ The Company chose 13 criteria for its technical analysis. The criteria included: space heating effects; space cooling effects; effects on lighting; sensitivity to non-utility implementation; relative market size; peak clipping; valley filling; kw impact in summer; kw impact in winter; kwh impact in summer; program implementation time; time to realize results; and developmental status (Exh. HO-I-14, p. 24).

13/ For example, the Company stated that heat pump water heaters with a ranking of 10 are not twice as attractive to the utility's demand management objectives as groundwater-coupled heat pumps, which received a technical value of 5 (Exh. HO-I-14, p. 28).

not volunteer to invest in a C&LM technology that provides less than a 30 percent IRR (id., p. 31). These two IRR for commercial and residential class customers are described as "hurdle rates" (id.).

In the next step of the process, the Company combined the results of the technical and economic analyses to identify C&LM options for inclusion in C&LM implementation programs (id., p. 36). In this step, the Company effectively generated three categories of C&LM technologies. The first category consisted of options with an exceptional technical value,[14] and an IRR above the hurdle rate for the residential or commercial class. The second category consisted of technologies with high technical values, but with marginal IRR (id.). The third category consisted of technologies with low technical values and low IRR (id., p. 36).

The Company stated that for technologies in the first category -- high technical value with high IRR -- "an educational or promotional effort should be sufficient to ensure that they are adopted by customers" (id., p. 36). As a result, technologies in this category generally are not included in the C&LM programs that the Company markets to residential, commercial, and industrial customers. Conversely, if the technologies that are most attactive to NU are not economical to the customer, "a [C&LM] program may need to be designed that will remove or lessen any customer disincentives to invest in the technology" (id.). As a result, technologies in category two with a high technical value but an IRR below the assumed hurdle rates are the prime candidates for promotion through inclusion in C&LM programs (id.).[15] The Company stated that it selects the most promising commercial/industrial technologies, with attractive technical values and technologies from

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14/ The Company did not specify the minimum or maximum technical value a C&LM technology must attain to be considered exceptional.

15/ For example, NU suggests that the following C&LM programs with an IRR below the 50 percent hurdle rate are appropriate for inclusion in non-generational supply options for the commercial sector: high efficiency flourescent lighting (early replacement) with an IRR of 26.4 percent; daylight-following dimmers with an IRR of 16.6 percent; EMS systems with an IRR of 27.1 percent; and cool storage systems with an IRR of 12 percent (Exh. HO-I-14, p. 36).

category two, and places them in preliminary program plans (id., p. 41). These programs, and marketing strategies, become the non-generational supply options that are evaluated in later steps of the IDSP process (id.).

c. Ranking of Demand and Supply Resource Alternatives

After the technology screening process, NU ranked generational and non-generational supply options. In this process, the Company compared expansion plans containing each resource option as the incremental source of supply to a base case expansion plan.[16] NU considered a 386 MW combined-cycle unit that would come on line in 1998 to be the reference incremental source of supply (Exh. NU-5, Exhibit 1, p. 3).

NU performed the comparative analysis by modeling a replacement of all or part of the 386 MW combined-cycle unit from the base case with each of the resource options under consideration. The Company then evaluated the "revised" plan's value with regard to three standard measures, and compared these values to those for the base case. The three standard measures included: (1) cumulative present worth of revenue requirements differences per kilowatt of reliability contribution;[17] (2) utility cost per kilowatt of reliability contribution; and (3) revenue rate of return. Each standard measure created a separate ranking of resource options (id., pp. 16, 18, 20).

The Company did not state how the results of the financial

16/ The base case expansion plan analyzed in this section differs from the base case expansion plan described in Section III.D.1.a, supra, which reflected the Company's 1987 supply plan. The Company stated that the base case used in step 3 of IDSP was developed only for the purpose of ranking resource options, and not for decision making on resource commitments, and that this plan was produced from the 1986 supply plan with the exclusion of demand side management, life extension, and repowered fossil steam capacity (Exh. NU-5, p. 7).

17/ The reliability contribution of an option is the option's impact on the system's need for generating resources based on NEPOOL capability responsibility criteria (Exh. HO-I-13, p. 7).

simulations were interpreted to create a final integrated ranking of all resource options combined, nor did the Company provide a final ranking that listed each of these options in order of preference.

d. Combination of Supply Options into Alternative Resource Plans

The Company created eight resource plans based on options ranked in the previous IDSP steps. Each resource plan specified the technology options utilized to realize certain corporate and/or public energy policy objectives.

e. Resource Plan Evaluation

In the evaluation of alternative resource plans, NU focused on long-term electric resource supply strategies (Exh. NU-8, p. 1). The eight supply plans generated in the previous IDSP step varied with regard to the quantities of C&LM, qualifying facility ("QF") power purchases, and generation plant life extensions included. The Company stated that this enabled planners to "identify the effects of additional demand management, additional QF purchases, and/or removing life extension from the [base case] plan" (id., p. 3).

NU subjected each of the resource plans to: (1) revenue requirements analysis; (2) an electricity price analysis; (3) a financial risk assessment to determine capital costs; and (4) fuel supply diversity analysis.

f. Uncertainty Analysis

In the final step of the IDSP analysis, NU subjected the resource plan from the previous IDSP step that the Company believed was most promising, and one of the alternative plans, to an uncertainty analysis. This analysis examined the efficacy of these resource plans under oil price and load growth uncertainties. The Company established the probabilites for various events in these two categories using "informed staff opinion" (Exh. NU-10, p. 30). The probability analysis enabled the Company to determine which of the two plans was most likely to provide electricity at lowest cost under the greatest number of uncertainty scenarios. NU chose the resource plan which provided power to the system at the lowest cost under the greatest number of scenarios (Exh. HO-1.A, pp. A-34 - A-48).

2. Comparison of Supply Alternatives on an Equal Footing

In its reviews of electric utility supply plans, the Siting Council has consistently required a company to demonstrate that its supply planning process enables it to evaluate all demand-side supply options and generational supply options on an equal footing. Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 133-137 (1987); Boston Edison Company, 15 DOMSC 287, 339-349 (1987). In this case, the Company asserted that its IDSP process was designed to provide consistent evaluation of all supply options to ensure the lowest cost energy supply for the long run.

The Siting Council analyzes the IDSP process with regard to its requirement that all resource options in a supply plan be compared on an equal footing. In particular, the Siting Council focuses its review on the Company's screening processes for generational and non-generational sources of supply.

a. Screening of Supply Options

In the second step of the IDSP process, the Company screened both generational and non-generational sources of supply. The Siting Council notes that this step in the IDSP process is largely judgmental with regard to both generational and non-generational sources of supply. In fact, the Company stated that the method used to screen C&LM technologies relies on "experienced judgment to point to those DSM technologies ... likely to have a high probability of meeting a utility company's load shape objectives" (Exh. HO-I-14, p. 21). Further, the Company stated that for generational options, the screening process requires "essentially a distillation of the expertise and experience of technical personnel in NU's Research, Generation Engineering, and

Electric Supply Planning departments" (Exh. NU-6, p. 6).

In separate screening of generational and non-generational supply options, the Company employed both technical and economic analyses. In reviewing these screening processes, the Siting Council evaluates whether NU's technical and economic analyses allow it to evaluate generational and non-generational supply options on an equal footing.

i. Generational Technologies: Technical Analysis

NU identified 42 technologies as candidates for further study and possible inclusion in its resource plans (Exh. NU-6, p. 15). The Company then assessed each technology with regard to four qualitative criteria: (1) availability of the primary fuel resource within the NU service territory; (2) availability of data regarding the technology's performance and cost; (3) ability to license the technology in the NU service territory; and (4) an assessment as to whether the technology will be commercially available so that it can be placed in service by 2005 (id., p. 18).[18]

In performing the technical analyses of generational supply technologies, the Company described each technology option relative to the four criteria, concluding in a judgment as to whether the technology would be included in later stages of the IDSP process (see Exh. NU-7). These technical analyses resulted in the elimination of 20 generational technologies (Exh. NU-6, p. 19).

To determine whether NU's screening process evaluates

18/ The Company qualified the fourth criterion stating that acceptable technologies require,

> sufficient evidence that at least one commercial vendor of the technology option is or will be in business, or that current industry research and development efforts will result in a commercially available option. For example, with the planning horizon ending in 2005, a candidate technology expected to become commercially available in 2000 and operational within five years would just meet the screening criteria. Similarly, a technology with a ten-year lead time would have to be commercially available by 1995 to be applicable.
> (Exh. NU-6, p. 18)

generational technologies consistently, the Siting Council analyzes the Company's application of its technical criteria to two generational technologies screened in NU's IDSP process. As a result of its technical analysis, the Company eliminated the Steam Injected Gas Turbine ("STIG") technology while allowing the nuclear-fueled Modular Gas Reactor ("MGR") to proceed to the next step of the IDSP process. The Siting Council reviews how the Company applied its technical analysis to the MGR and the STIG technologies.

The STIG uses aircraft-type gas turbines in conjunction with a steam generator or boiler to capture hot exhaust gases. Steam is injected into the combustion chamber to decrease NOx emissions, increase turbine power output, and increase generating efficiency (id., p. 18). The Company stated that the STIG is in the demonstration phase of development, with one unit operating in California (id., p. 19).

The MGR, a type of high-temperature, gas-cooled nuclear reactor, is a technology that uses helium gas instead of water to transfer heat from a nuclear reactor core to a steam generator. The MGR is in the development stage, with the next steps being the design and construction of a 150 MW module of a 600 MW plant planned for operation in the late 1990's (id.).

As a result of its technical analysis, the Company rejected the STIG for failing to satisfy criterion two, the lack of available data regarding the technology's performance and cost, and criterion four, ability of the technology to be commercially available and in service by 2005. At the same time, the Company found that the MGR technology satisfied all criteria and warranted consideration in subsequent steps of the IDSP process (Exh. NU-6, p. 20).

In applying criterion one, the Company found that both STIG and MGR utilized a fuel source that was available in NU's service territory (id.). The Siting Council notes that while the the STIG uses natural gas, the MGR requires nuclear fuel, which the Company conceded is subject to some uncertainty (Exh. NU-7, p. 40). In fact, the Company stated that governmental financial support is required for development of a new nuclear fuel cycle (id.). Further, due to MGR requirements for nuclear fuel enrichment, the Company estimated MGR fuel costs would be 39 percent higher than conventional nuclear fuel (Exh. NU-6, p. 75).

Still, the Company finds that both the STIG and the MGR satisfy criterion one.

In applying its second criterion -- availability of data on technology performance and costs -- NU required the availablity of sufficient data to enable the Company to make reasonable judgments about a particular technology (id., p. 18). The Company found that in the case of STIG, a demonstration unit is already operating in California (Exh. NU-7, p. 19). At the same time, the Company stated that it expects initial operation of a prototypical MGR plant sometime in the late 1990's (Exh. NU-7, p. 39).[19] Still, the Company rejected the STIG while finding that the MGR satisfied the requirements set forth in criterion two.

NU's third criterion required a reasonable expectation that a generational supply technology can be licensed in NU's service territory (Exh. NU-6, p. 18). In regard to the STIG, the Company stated that the natural gas-fired STIG's combustion process causes less environmental impact than other combustion turbine options (Exh. NU-7, p. 18). In light of this positive environmental assessment, NU concluded that an STIG plant could be licensed in the NU service territory (Exh. NU-6, p. 20).

At the same time, the record in this proceeding indicates that the MGR might face some uncertainty in obtaining a license in NU's service territory. The Company stated that nuclear technologies are affected by (1) the unpredictable regulatory environment; (2) long lead times; and (3) increased risk to investors (Exh. HO-I-1.A, pp. IV-21 - IV-23). Still, in light of these factors, the Company determined that the MGR also satisfied the licensability criterion.

NU's fourth criterion required that a technology be commercially available "so that it can be placed in service on the NU system by 2005" (Exh. NU-6, p. 18). The Company noted that a STIG system currently operates as a cogeneration unit in California (Exh. NU-7, p. 19), and

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19/ In the qualitative assessments set forth in Exh. NU-7, the Company has provided no evidence of on-going siting or construction of this prototype MGR in New England or elsewhere.

that STIG technology will be commercial by 1995 (id., p. 20). However, the Company rejected the STIG technology from further IDSP analysis for failing to meet the requirements of criterion four.

In contrast, the Company asserted that the MGR meets the requirements of criterion four despite a variety of factors that might affect its availability. First, the Company asserted that a "pre-commercial" rendition of the MGR would be on line until the late 1990's. Secondly, NU recognized that financial considerations may affect the availability of the MGR by 2005. The Company stated that the first MGR to be constructed would require cooperative private and public sector arrangements paying 75 percent of the total costs, and that government financial support would be required for the first-of-a-kind design and technology development for nuclear systems, components, and the fuel cycle, as well as to offset first-of-a-kind risks associated with the lead plant (Exh. NU-7, p. 40). In light of these factors, the Company nonetheless determined that the MGR satisfied criterion four.

The Siting Council finds that the application of NU's technical criteria to the STIG and MGR technologies reveals substantial problems in this stage of the Company's screening process. The Siting Council recognizes that its analysis of NU's technical screening process for generational alternatives is limited to only two technologies. Still, the application of the screening process to STIG and MGR raises doubts as to whether the Company narrowed its range of options in a manner consistent with its own standards of review.

In sum, the Siting Council finds that the Company relies too heavily upon judgment in its initial generational technology screening process, precluding a balanced application of technical criteria for each generational technology. NU's application of specific criteria to these technologies reveals that the Company's technical analysis may recommend a technology for further IDSP analysis which fails to meet the Company's stated screening criteria, while possibly rejecting a technology which satisfies each of the Company's criteria.

In making this finding, the Siting Council is not rejecting a particular screening criterion, nor indicating a preference for a particular technology. Rather, the Siting Council requires companies to establish that its screening criteria are applied in a consistent manner. The consistent application of these criteria is particularly important when those technologies that fail to meet criteria are eliminated from further consideration.

Accordingly, the Siting Council finds that the Company has failed to establish that its technical screening process for generational supply technologies evaluates all generational supply technologies on an equal footing.

The Siting Council discusses the application of different technical analyses to generational and non-generational technologies in Section III.E.2.a.iii, infra.

ii. Generational Options: Economic Analysis

The economic analysis in the Company's screening process is described in Section III.E.1.b.i, supra. In the analysis of 66 technology options, the Company focused on the 20-year levelized busbar cost of each generation option over a range of capacity factors (Exh. NU-6, p. 35).[20] The Siting Council finds that this type of busbar cost analysis enables the Company to evaluate each technology option on a consistent basis. In fact, the graphic presentation of the results of the busbar cost analysis is particularly helpful in identifying cost-effective generation options. In addition, the Company stated that qualitative criteria were factored into the economic analysis of generational options when busbar costs were similar. The Siting Council finds that the use of qualitative criteria in these instances may be appropriate.

Accordingly, the Siting Council finds that NU's economic screening process for generational supply options evaluates all generational supply options on an equal footing.

The Siting Council discusses the application of different economic analyses to generational and non-generational options in Section III.E.2.a.iv, infra.

20/ In its analysis of 20-year levelized busbar costs, the Company separated generation options into baseload, intermediate, peaking, renewable resource-based technology options, quick installation options, and energy storage options (Exh. NU-6, pp. 35-48).

iii. Non-generational Technologies: Technical Analysis

The technical analysis for non-generational supply technologies evaluates each technology from the utility's perspective. As in the case of the technical analysis of generational techologies, the Company assigned some measure of judgment to each non-generational option. In the case of non-generational technologies, NU's technical analysis assigned qualitative values to each technology on the basis of 13 established criteria. While the Siting Council accepts the Company's criteria, the Siting Council makes no finding as to whether the 13 criteria have been applied in a fair and consistent manner.

The application of the Company's technical criteria to non-generational supply technologies, however, raises other important questions about the screening process. While the Company assigned qualitative values to each non-generational supply option, there is no evidence that any of these technologies are eliminated on the basis of technical value. Instead, the technical values for non-generational technologies are juxtaposed against the results of an economic analysis of these options to determine which non-generational technologies will continue to the next step of the IDSP process.

This approach is substantially different from the technical analysis applied to generational technologies. In the technical analysis of generational technologies, technologies that fail to meet certain criteria are eliminated prior to any economic analysis. In past reviews of electric company supply plans, the Siting Council has criticized companies that fail to directly compare demand-side and supply-side supply options. Boston Edison Company, 15 DOMSC 287, 341-349 (1987). In this case, the Siting Council finds that the application of technical criteria to demand-side and supply-side options is not parallel, and may not contribute to a direct comparison of all supply options on an equal footing.

iv. Non-generational Options: Economic Analysis

In its economic analysis of non-generational supply options, the Company ranks C&LM technologies from the consumer perspective by calculating each technology's internal rate of return (see Section

III.E.1.b.ii, supra). In using a screening process based on the customer's IRR, the Company failed to consider other factors which may contribute to a consumer's decision regarding C&LM options. Specifically, the Company failed to demonstrate that its screening process for non-generational supply options incorporates such factors as (1) customer income; (2) capital costs; and (3) whether a customer is a property owner or tenant.

Furthermore, the Company stated that C&LM technologies with IRR above the hurdle rate require only informational and promotional campaigns to "ensure" that they are implemented in the marketplace (Exh. HO-I-14, pp. 30, 36). In effect, the Company focused its efforts on those technologies having only a marginal rate of return on investment, rather than those with a particularly high IRR. As a result, the Company does not include those C&LM programs with the highest IRR in the group of demand-side programs promoted with economic incentives.

Accordingly, the Siting Council finds the Company has failed to establish that its economic screening process for non-generational supply options evaluates all non-generational supply options on an equal basis.

Further, in its economic screening of generational supply options, NU used levelized busbar costs to compare alternatives, while in its economic screening of non-generational supply options, the Company used an analysis of a consumer's IRR to compare options. In effect, the Company used its own costs to evaluate generational options, and a consumer's costs to evaluate non-generational options, resulting in two unrelated standards for screening generational and non-generational supply options. Therefore, the Siting Council finds that the application of economic criteria to demand-side and supply-side options is not parallel, and may not contribute to a direct comparison of all supply options on an equal footing.

b. Summary of Analysis of Screening Processes

Based on the foregoing, the Siting Council finds that the Company's application of its screening processes does not enable it to evaluate all generational and non-generational supply options on an equal footing.

3. Conclusions on Least-Cost Supply

In this proceeding, the Siting Council has attempted to review the Company's IDSP process to determine whether this process enables the Company to ensure a least-cost energy supply for its customers. As part of that review, the Siting Council has limited its focus to the screening stage of the Company's IDSP process.

The Siting Council has found that (1) the Company's technical screening process for generational supply technologies fails to evaluate those technologies on an equal basis; (2) the Company's economic screening process for non-generational supply options fails to evaluate those options on an equal basis; and (3) the application of the Company's screening process, on the whole, may not enable the Company to evaluate both generational and non-generational supply sources on an equal footing.

Still, while these findings raise serious questions about the ability of the IDSP process to ensure a least-cost supply plan, the Siting Council notes that its review of NU's supply plan has narrowly focused on just one stage of the IDSP process.

In some part, the Siting Council's review of NU's supply plan has been limited by the Company's presentation. Throughout this proceeding, the Company has provided the Siting Council with numerous documents addressing different aspects of the IDSP process. In many cases, these documents have been either outdated or inconsistent.[21]

21/ As an example, the Siting Council notes that, in response to a discovery request, the Company confirmed that with the exception of certain "slight changes," a document entitled "Northeast Utilities Integrated Demand/Supply Planning 1983-1985" remained the "foundation" of the Company's resource planning process (Exh. HO-IDSP-9). However, at the hearing, the Company's witness, Mr. Stillinger, testified that a number of updated documents regarding the IDSP process had not been entered in the record (Tr. II, pp. 27-29).

In many cases, these documents (Exhs. NU-5, NU-6, NU-7, NU-8, NU-10) superseded previously filed documents regarding the IDSP process. The Siting Council notes that many of these updated documents had been available for more than one year before the Siting Council's hearings in this matter, yet the Company failed to submit these critical documents on its own initiative or in response to discovery requests.

As part of its next filing, the Siting Council ORDERS the Company to provide a clear, detailed, and comprehensive narrative which (1) sets out the various steps of its IDSP or current planning process, and (2) includes all current and relevant documents regarding that process.

Therefore, in light of the limited focus of its review, the Siting Council makes no finding regarding the least-cost nature of the Company's supply plan.

F. Diversity of Supply

In 1987, nuclear fuel provided 67 percent of the Company's energy requirements (Exh. HO-2, p. III-29). The Company expects to add only an additional 47 MW of nuclear power to its system if the Seabrook power plant comes on line. Otherwise, the Company expects to add 187 MW of hydroelectric power from Hydro-Quebec in 1991, retire more than 800 MW of fossil-fuel plants, purchase over 1,300 MW from NYSPA and cogenerators, and small generators, and life-extend nuclear and fossil-fuel generating stations. These trends indicate the Company is acting to maintain a diverse primary fuel supply. Accordingly, the Siting Council finds the Company's primary fuel supply is adequately diversified.

G. Conclusions on the Supply Plan

The Siting Council has found that the Company has complied with Conditions Five and Six of its last decision.

The Siting Council also has found that the Company has adequate supplies in the short run, while making no finding in regard to the long-run planning process.

Further, while the Siting Council has found that the Company has failed to establish that it compares generational and non-generational options on an equal basis, the Siting Council makes no finding as to whether the Company's planning process ensures a least-cost supply of energy resources.

Accordingly, the Siting Council approves Northeast Utilities' 1986 and 1987 supply plans.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the 1986 and 1987 demand forecasts and supply plans of Northeast Utilities as presented in the 1986 Long-Range Forecast of Electrical Loads and Power Facilities Requirements and the 1987 Annual Supplement to that forecast.

The Siting Council ORDERS Northeast Utilities in its next forecast filing:

1. to present an analysis of each of the economic factors which may have an impact upon commercial floorspace growth;

2. to file supporting documentation describing (a) each of the variables used in the industrial class econometric model, and (b) the theoretical basis for using non-linear estimation in the industrial class model; and

3. to provide a clear, detailed, and comprehensive narrative which (a) sets out the various steps of its IDSP or current planning process, and (b) includes all current and relevant documents regarding that process.

The Siting Council FURTHER ORDERS Northeast Utilities to file their next demand forecast and supply plan on April 1, 1989.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of May 26, 1988, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Stephen D. Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Joseph W. Joyce (Public Labor Member).

Sharon M. Pollard
Chairperson

Dated this 26th day of May, 1988

TABLE 1

Western Massachusetts Electric Company[a]
Demand Forecast by Customer Class

WMECO	Annual Energy Requirements (GWH) 1987	1996	Average Annual Compound Growth Rate 1987-1996
Residential	1312	1427	0.8%
Commercial	1185	1231	0.4%
Industrial	1187	1336	1.2%
Streetlighting	31	27	(1.4%)
Wholesale Sales	173	206	1.8%
Losses/Internal	299	334	1.1%
Total	4187	4561	0.9%

	Peak Capacity Requirements (MW)		Average Annual Compound Growth Rate 1987-1996	
	1987	1996	WMECO	NU[b]
WMECO[c] Winter	742	815	0.9%	---
NU System[d] Summer	4516	5454	---	1.9%
NU System Winter	4569	5523	---	1.9%

Notes:

a. All statistics for WMECO include HWP and its subsidiaries.

b. Statistics for NU include all its Massachusetts and Connecticut subsidiaries.

c. WMECO forecasts a winter peak for the duration of the forecast period.

d. NU forecasts higher peak demands in successive summer and winter periods throughout of the forecast.

Sources: Exhs. HO-1, HO-2, HO-8

TABLE 2

Northeast Utilities System
Consolidated Demand Forecast and Supply Plan
Summer & Winter Peaks (MW)

Year	Estimated[a] Capability Respons. Summer	Total Supply	Surplus/ (Deficit)	Estimated Capability Respons. Winter	Total Supply	Surplus/ (Deficit)
1988	5396	5836	440	5546	6003	457
1989	5578	5997	419	5610	6157	547
1990	5571	6272	701	5751	6575	824
1991	5523	6467	944	5873	6871	999
1992	5647	6748	1101	6031	6871	839
1993	5786	6728	942	6155	6854	699
1994	5905	6729	824	6272	6783	511
1995	6066	6672	606	6400	6587	188
1996	6205	6516	311	6628	6587	(41)

Notes:

a. The Company reduces its summer capability responsibility for energy purchases pursuant to the Hydro-Quebec Phase I and Hydro-Quebec Phase II agreements (Exh. HO-2, p. III-27). These reductions are 153 MW through 1990 and 340 MW for the remainder of the forecast period.

Sources: Exhs. HO-2, HO-8

TABLE 3

Northeast Utilities System
Short-Run Contingency Analysis
Summer Peak Load (MW)

1. High Load Growth Scenario[a]

Year	High Load Growth Forecast	Estimated[b] Capability Respons.	Total Supply	Contingency Surplus (Deficit)
1988	4825	5580	5836	256
1989	5009	5884	5997	113
1990	5145	5965	6272	307
1991	5290	6008	6468	460

2. Cancellation or Delay of Seabrook 1[c]

Year	Base Case[d] Surplus (Deficit)	Loss of Seabrook 1	Contingency Surplus (Deficit)
1988	440	0	440
1989	419	(47)	372
1990	701	(47)	654
1991	944	(47)	897

3. High Load Growth and Cancellation or Delay of Seabrook 1

Year	Estimated[b] Capability Respons.	Total Supply	Loss of Seabrook 1	Contingency Surplus (Deficit)
1988	5580	5836	0	256
1989	5884	5997	(47)	66
1990	5965	6272	(47)	260
1991	6008	6468	(47)	413

Notes:

a. The Company's high load growth scenario assumed 3.2 percent compound annual load growth. See Section III.D.1.c.i, *supra*.

b. Capability responsibilities are adjusted for Hydro-Quebec purchases.

c. The Company assumed it would begin receiving its Seabrook 1 entitlement of 47 MW in April 1989. See Section III.D.1.c.ii, *supra*.

d. See Table 2 for short-run base case surplus/deficit.

Sources: Exhs. HO-2, HO-11

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of North Attleboro Gas Company for Approval of the Fourth Annual Supplement to the Second Long-Range Forecast of Natural Gas Requirements and Resources	)	EFSC 86-22

FINAL DECISION

Frank P. Pozniak
Hearing Officer

On the Decision:

Pamela J. Maclean
Sheri L. Bittenbender

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The Energy Facilities Siting Council hereby APPROVES the sendout forecast and supply plan filed by North Attleboro Gas Company for the five years from 1986-87 through 1990-91.

I. INTRODUCTION

A. Background

North Attleboro Gas Company[1] ("North Attleboro" or "Company") distributes and sells gas to approximately 2500 customers in the towns of North Attleboro and Plainville (Exh. HO-SF-14). The Company has approximately 2200 residential-domestic customers, 100 residential-space heating customers, 150 commercial customers, and 50 industrial customers (Exh. HO-SF-10).

The Company has not proposed to construct or acquire any jurisdictional facilities during the forecast period.[2]

North Attleboro's forecast of sendout by customer class for the heating and non-heating seasons is summarized in Table 1 (Exh. C-1). The Company projects an increase of total normalized firm sendout from

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1/ In March of 1987, the stock of North Attleboro Gas Company was purchased by the Providence Energy Corporation, which is also the parent corporation of Providence Gas Company. North Attleboro, however, conducts its business as an independent entity (Exhs. HO-B1, HO-B2).

2/ The Company is committed to 9.6 miles of main extension to be completed over two years (Exh. HO-RR-2). By the close of this proceeding, approximately one-half of the construction had been completed (id.). The Company provided that the main is being installed with a maximum allowable operating pressure of approximately 133 pounds per square inch guage ("psig") (Tr. II, pp. 23-24). However, North Attleboro also provided that it does not plan to operate the main in excess of 100 psig for the next five to ten years (Tr. II, pp. 24-25, 34).

Pursuant to G.L. c. 164, sec. 69G, a "gas facility" is defined in part as "any new pipeline for the transmission of gas having a normal operating pressure in excess of one hundred pounds per square inch guage which is greater than one mile in length." In that North Attleboro's 9.6 miles of main will not operate at a pressure in excess of 100 psig, the facility is not jurisdictional. However, pursuant to 980 CMR 7.07(8)(d), the main may be considered a jurisdictional facility if it is used at a pressure in excess of 100 psig within the first two years of service.

247 BBtu in 1986-87 to 263.2 BBtu in 1990-91, representing an average annual growth of 1.6 percent (id.). North Attleboro receives gas supplies primarily from Algonquin Gas Transmission Company ("Algonquin"), but also from Bay State Gas Company ("Bay State") under a peak shaving contract (Exh. HO-B2). North Attleboro's previous forecast was approved by the Energy Facilities Siting Council ("Siting Council") without conditions. North Attleboro Gas Company, 14 DOMSC 33, 39 (1986).

B. History of the Proceeding

On November 5, 1986, North Attleboro filed its sendout forecast and supply plan. A Notice of Adjudication was issued by the Hearing Officer on February 19, 1987, directing the Company to publish and post the Notice in accordance with 980 CMR 1.03(2).

In March of 1987, Providence Energy Corporation purchased North Attleboro. On June 9, 1987, the Hearing Officer directed the new management of North Attleboro either to file a new forecast or to adopt the previously filed sendout forecast and supply plan. On June 26, 1987, North Attleboro filed a new sendout forecast and supply plan ("1986 Forecast"). A second Notice of Adjudication was issued by the Hearing Officer on June 29, 1987, directing the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). The Company confirmed publication and posting. There were no intervenors or interested persons in the proceeding.

On December 14, 1987 and February 3, 1988, the Siting Council conducted evidentiary hearings. The Company presented three witnesses: George E. Briden, manager of gas acquisition for the Providence Energy Corporation; Guy Marchetti, general manager of North Attleboro; and Edward Smith, a consultant from Stone and Webster. The Siting Council offered 31 exhibits into the record, composed of the Company's responses to information and record requests.[3] The Company presented one exhibit into the record, its 1986 Forecast.

3/ At the hearing held on February 3, 1988, the Hearing Officer took administrative notice of the Department of Public Utilities' decision in North Attleboro Gas Company, D.P.U. 86-86 (1986) (Tr. II, p. 41).

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

As part of its statutory mandate "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, sec. 69H, the Siting Council determines whether projections of gas requirements "are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. A forecast that is based on accurate and complete historical data as well as reasonable statistical projection methods should provide a sound basis for resource planning decisions. Berkshire Gas Company, EFSC 86-29, p. 2 (1987).

In its review of a forecast, the Siting Council determines if a projection method is reasonable according to whether the methodology is (a) reviewable, that is, contains enough information to allow a full understanding of the forecasting methodology; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments and data will forecast what is most likely to occur. Berkshire Gas Company, EFSC 86-29, pp. 2-3 (1987); Bay State Gas Company, 14 DOMSC 143, 150 (1986); Boston Gas Company, EFSC 84-25, p. 8 (1986).

B. Normal Year and Design Year

1. Description

North Attleboro forecasted normal year and design year sendout for its residential-domestic customers, residential-space heating customers, commercial customers, and industrial customers based on normal year and design year standards, average use per customer, and customer number projections (Exh. HO-SF-1). The results of the Company's normal year and design year forecasts are summarized in Table 1.

To develop its normal year standard, the Company calculated the degree days ("DD") for each of 12 normal months by averaging the total

DD in the respective months for a 15-year period, 1970-85, and summing the averages (Exhs. HO-SF-4, HO-SF-11; Tr. I, p. 12). Based on this method, the Company defined its normal year as 6,928 DD (Exh. HO-SF-4).

North Attleboro developed its design year standard by adding incremental DD to the normal year standard for each month during the heating season (Exh. HO-SF-5; Tr. I, pp. 12-16). These monthly incremental DD were based on historical four-day DD peaks which occurred during the four heating seasons 1983-84 through 1986-87 (id.). Based on this method, the Company defined its design year as 7,260 DD (id.).

The Company indicated that its normal year and design year weather databases were based on actual DD data for the service territory, but did not identify how the data were generated (Exhs. HO-SF-16, HO-SF-17). The Company stated that it based its design year standard on only four heating seasons as opposed to the 15 heating seasons used for the normal year because the September 1983 through March 1987 database "was the most current and complete set of data available" (Exh. HO-SF-17).

North Attleboro determined average use per customer for each of its four customer classes by regression analyses of historic monthly sales in each class versus DD over the 36-month period from March 1984 through February 1987 (Exhs. HO-SF-1, HP-SF-2). The Company factored seasonal variations in customer DD response rates directly into its analysis (Exh. HO-SF-2). North Attleboro stated that the effects of other factors, such as tariffs, demographics, and appliance saturation, were represented indirectly in the analysis through use of a lagged consumption variable (Exh. HO-SF-2). The Company did not indicate whether it factored conservation estimates into its customer use factors.

To project customer numbers, North Attleboro determined the average number of customers for each class in 1986 based on monthly customer numbers, then estimated the net customer gain per class for each month over the five-year forecast period (Exh. HO-SF-3). The Company stated that, due to the recent change in Company management, it has not yet fully analyzed growth potential and developed appropriate marketing strategies (Tr. I, pp. 8-10). For purposes of this forecast filing, North Attleboro provided the following basis for its net customer gain per class:

> These predictions are simply an intuitive best guess prepared for the purposes of this exercise. We know of no reliable statistical technique that might be employed to generate reliable customer numbers for such a long time horizon from such a small data base. There is no recourse here except to "guessestimates [sic]". (Exh. HO-SF-3).

The Company's estimates reflect a net anticipated growth of 189 residential-domestic customers, 10 residential-space heating customers, 3 commercial customers, and 2 industrial customers over the five-year forecast period (Exh. HO-SF-3). The Company stated that, while it does not currently serve any interruptible customers, it anticipates that current distribution system construction will lead to a development of that market (Tr. I, pp. 8-12).

2. Analysis

The Siting Council finds that North Attleboro has established that its normal year and design year sendout forecasts are reviewable.

North Attleboro's methodology for determining its normal year standard -- averaging historical DD for the service territory over a 15-year period -- is acceptable for a small company. Although a gas company is required to identify and establish the reliability of its source of weather data, for the purposes of this review, the Siting Council accepts the Company's assertion that its weather data is the only data available for its service territory.

While the use of historic cold spells as a basis for a design year standard is acceptable, the use of only four years of weather history as a database raises concerns about the stability of the results. The Company failed to provide sufficient justification for using such a small database. Further, the Company provided no theoretical basis for its use of incremental design DD based on historic four-day DD peaks within each heating season month. This methodology does not account for potential design year conditions, but instead is effectively limited to four-day cold snaps. However, for the purposes of this review, the Siting Council finds this methodology to be acceptable.

North Attleboro's methodology for determining its average use per customer is relatively sophisticated for a small company. The Company developed a regression model from sendout data and used the model to forecast customer DD response rates for the summer, winter, and shoulder months throughout the five-year forecast period.

North Attleboro's implementation of this methodology, however, has two apparent weaknesses. First, the Company did not fully explain the theoretical basis for the lagged consumption variable in its regression model. While the Company indicated that this variable was intended to capture certain changes in customer consumption rates, the Company failed to establish that there is a clear relationship between changes in consumption and the lagged-variable methodology. Second, while the Company stated that it intended to capture certain changes in consumption rates over the forecast period by using the lagged-variable methodology, it did not attempt to capture changes in customer consumption in a more direct manner. For instance, customer DD response rates did not reflect changes due to conservation or new appliance efficiency standards. Despite these weaknesses, the Company's methodology for determining average use per customer is acceptable.

The Company's projections of customer numbers were not based on historical trends or any other identified bases, but rather on what the Company described as "guessestimates". The Company asserted that, due to new management, it lacks experience with this specific customer base and therefore a conservative projection of customer numbers was appropriate for this filing. While a methodology of judgmental estimates is acceptable for a small company, the reliability of the results depends on a company's knowledge of its customer base. However, for the purposes of this review, the Siting Council accepts the Company's methodology for projecting customer numbers.

3. Conclusions

The Siting Council has found that the Company's normal year and design year forecasts are reviewable. The Siting Council also has reviewed North Attleboro's methodologies for determining its normal year standard, design year standard, average use per customer, and customer number projections and finds that North Attleboro's normal year and design year forecasts are minimally appropriate and reliable.

However, the Siting Council ORDERS North Attleboro in its next forecast filing (a) to justify the use of different ranges of weather data for its normal year and design year standards, (b) to establish the reliability of its weather databases for North Attleboro's service territory, (c) to justify the use of a methodology for determining its design year standard based on four-day historical peaks, and (d) to justify its projections of customer numbers.

C. Design Day[4]

1. Description

North Attleboro plans for a design day of 65 DD (Exh. HO-SF-1). The Company stated that this number (1) was introduced by new company management based on the design day used by the Providence Gas Company, (2) is conservative relative to the last five years when the coldest day in the North Attleboro service territory was 64 DD, and (3) is reviewed annually to ensure continued applicability (Tr. I, pp. 16-17; Exh. HO-SF-19).

North Attleboro calculated design day average use per customer as the sum of (1) the normal average use per customer for February and (2) the product of (a) the customer DD response rates for each class, (b) the difference between a design day (65 DD) and a normal February day (43.5 DD), and (c) a "gross up" factor (id.). The Company stated that it uses the "gross up" factor to reflect changes in customer DD response rates due to weather severity and, for this forecast, estimated the factor by calibrating the formula to the Company's highest sendout

4/ In this decision, the Siting Council uses "design day" as synonymous with "peak day."

during 1986-87 (id.). The Company stated that February was chosen as the design day month based on the service territory's most recent heating season because "the more current the actual data date to the basis of the extrapolation, the more relevant the results" (Exh. HO-SF-20; see also Exh. HO-SF-9). Finally, the Company forecasted design day sendout for each class by multiplying design day average use per customer by the customer number projections and the sendout to sales ratio for each class (Exh. HO-SF-1).

The results of the Company's forecast of design day requirements are summarized in Table 1.

2. Analysis

The Siting Council finds that North Attleboro has established that its design day sendout forecast is reviewable.

The Siting Council previously accepted North Attleboro's methodology for projecting customer numbers (see Section II.B.2, supra). Therefore, in its evaluation of North Attleboro's design day forecast, the Siting Council reviews (1) the determination of design day DD and (2) the development of design day average use per customer.

North Attleboro chose its design day standard of 65 DD judgmentally, supported by the observation that 65 DD had not been exceeded over the previous five years. In the past, the Siting Council has found that judgmentally set design standards are appropriate for small companies. North Attleboro Gas Company, 14 DOMSC 33, 34 (1986). However, the Company failed to provide sufficient justification for the use of a different range of weather data as the basis for its design day standard than that used for its normal year standard.

In that the methodology used by the Company to determine its design day customer DD response rates is the same as that used to determine its normal year and design year customer DD response rates, the Siting Council need not repeat its previously articulated concerns regarding this determination (see Section II.B.2, supra). With respect to its choice of February as the design day month, the Company provided no documentation supporting the statistical significance of using a single year of data for selecting the design day month. Thus, the Company failed to establish that its methodology for selecting the design day month is based on reasonable statistical projections.[5]

The Siting Council finds the use of a "gross up" factor, calibrated to actual weather history to reflect customer consumption variations related to severe weather, to be acceptable for a company of this size.

Although the Company's design day forecasting methodology has raised several questions concerning its appropriateness and reliability, for the purposes of this review, the Siting Council finds that this methodology is minimally appropriate and reliable.

The Siting Council ORDERS North Attleboro in its next forecast filing (a) to justify the use of a different range of weather data as the basis for its design day standard than that used for its normal year standard, and (b) to justify the appropriateness of its methodology for choosing its design day month.

D. Summary

In summary, the Siting Council has found that the Company provided adequate information for the Siting Council to review its methodologies for forecasting normal year, design year, and design day sendout. The Siting Council also has found that the Company's methodologies for developing its normal year, design year, and design day sendout forecasts are appropriate and reliable.

Accordingly, the Siting Council hereby APPROVES North Attleboro's forecasts of sendout requirements.

5/ The Siting Council notes that the Company's 15-year weather history used to determine its normal year standard established January as the coldest month historically followed by December then February. North Attleboro Gas Company, D.P.U. 86-86, p. 58 (1986).

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate "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, sec. 69H, the Siting Council has traditionally reviewed three dimensions of every utility's supply plan: adequacy, reliability, and cost. Berkshire Gas Company, 14 DOMSC 107, 128 (1986); Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986); Fall River Gas Company, 15 DOMSC 97, 111 (1986). While the Siting Council has broadly defined adequacy as the ability to meet projected normal year, design year, design day and cold-snap firm sendout requirements with sufficient reserves, the changing character of the gas market and an increasing reliance upon transportation projects that are subject to delay and cancellation requires the Siting Council to review adequacy both in terms of a company's base plan and its contingency plan.[6] Berkshire Gas Company, EFSC 86-29, p. 17 (1987).

Therefore, in order to establish adequacy, a gas company must demonstrate that it has an identified set of resources to meet its projected sendout under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources to meet sendout requirements under a reasonable range of contingencies, the company must then demonstrate that it has an action plan to meet projected sendout in the event that the identified resources will not be available when expected (id.).

6/ In the past, the Siting Council has reviewed the adequacy of a gas company's supply plan in the event that certain existing resources become unavailable. Boston Gas Company, EFSC 84-25, p. 33 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986); Fall River Gas Company, 15 DOMSC 97, 115 (1986); Berkshire Gas Company, 14 DOMSC 107, 127 (1986); Bay State Gas Company, 14 DOMSC 143, 168 (1986); Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

In adopting an expanded definition of adequacy for gas companies, the Siting Council notes that it is no longer necessary to make specific findings regarding the reliability of a company's resource plan. Instead, through review of a company's base plan under a reasonable range of contingencies and, if necessary, an action plan, the Siting Council has developed an adequacy standard which incorporates concerns regarding the reliability of a company's supply plan (id., p. 18).

The Siting Council also reviews the cost of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies (id.).

The Siting Council recognizes that a company's supply planning process is continuous, and that some balance is always required between the adequacy, cost, and environmental impacts of different supply sources. The Siting Council also recognizes that a company's supply options are affected by conditions existing or expected to exist in its market area and by supplies available in the region. Thus, each company's supply plan will be different, and the Siting Council recognizes the unique factors affecting the particular company under review. The Siting Council reviews each company's basis for selecting a supply alternative, or the company's decision making process which led it to select that supply alternative, to ensure that the company's decisions are based on forecasts founded on accurate historical information and sound projection methods. Berkshire Gas Company, 14 DOMSC 107, 128 (1986).

B. Adequacy of Supply

In reviewing North Attleboro's current supply plan, the Siting Council must determine whether the Company has adequate resources to meet projected sendout requirements under a reasonable range of contingencies. In order to make this determination, the Siting Council examines whether the Company's "base case" resource plan is adequate (1) to meet firm sendout requirements under normal year, design year, and design day conditions,[7] and (2) to meet those firm sendout requirements under a reasonable range of supply contingencies. Berkshire Gas Company, EFSC 86-29, p. 22 (1987).

1. <u>Evaluation of Base Case Resources</u>

North Attleboro receives deliveries of gas on a firm basis from Algonquin under rate schedules F-1, F-2, F-3, and WS-1 with annual contract quantities ("ACQ") totalling 272.4 BBtu, and a heating season maximum daily quantity ("MDQ") of 1182 MMBtu (Exh. C-1). Algonquin also provides storage and best efforts return under rate schedule STB with an ACQ of 9 BBtu and and MDQ of 94 MMBtu (id.). Additionally, Bay State provides firm peak shaving supplies at an ACQ of 20 BBtu and and MDQ of 1440 MMBtu during the heating season (id.). North Attleboro's forecast indicated that all contracts extend through the forecast period with constant delivery quantities (id.). The Company has propane storage facilities with a total capacity of 50,000 gallons (approximately 4575 MMBtu) capable of delivering 1200 MMBtu per day (Exh. HO-SP-3).

Accordingly, the Siting Council finds that, throughout the forecast period, North Attleboro can reasonably rely for base case planning purposes on (1) its full contractual volumes under rate schedules F-1, F-2, F-3, and WS-1, (2) its full contractual volumes from Bay State, and (3) its propane plant.

2. <u>Base Case Analysis</u>

In normal year and design year planning, North Attleboro must have adequate supplies to meet the requirements of its firm customers. The Company's normal year and design year supply plans indicate that the Company has adequate supplies to meet forecasted normal year and design year requirements throughout the forecast period (Exh. HO-SP-1).

Accordingly, the Siting Council finds that North Attleboro has established that its base case supply plan is adequate to meet forecasted firm normal year and design year sendout requirements.

7/ The Siting Council does not require small companies such as North Attleboro to prepare cold snap analyses. See <u>Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities</u>, EFSC 85-64, 14 DOMSC 95, 105 (1986).

North Attleboro also must have adequate supplies to meet the requirements of its firm customers on a design day. While the total supply capability necessary for meeting normal year and design year requirements is a function of the aggregate volumes of gas available over some contract period, design day supply capability is determined by the maximum daily deliveries of firm pipeline gas and the maximum rate at which supplementals may be dispatched.

Table 2 summarizes North Attleboro's forecasted design day sendout requirements and design day supply plan. In all years, the Company's base case supply plan would meet forecasted design day requirements.

Accordingly, the Siting Council finds that North Attleboro has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirements in all years of the forecast period.

3. Contingency Analysis

North Attleboro's supply plan is based on existing contracts for firm supplies which extend throughout the forecast period and does not include any new supplies or facilities. Since no reasonable contingencies were identified during the course of this proceeding, the Siting Council finds that there are no supply contingencies for which the Company must reasonably plan.

4. Conclusion

Based on the record, the Siting Council finds that North Attleboro has established that its base case supply plan is adequate to meet firm sendout requirements under normal year, design year, and design day conditions.

C. Least-Cost Supply

The Siting Council recently articulated its concerns regarding the need for gas companies to engage in least-cost planning. In its Order in EFSC 85-64, the Siting Council found that it was appropriate to focus on that portion of its mandate that requires the Siting Council to ensure an energy supply for the Commonwealth "at the lowest possible cost." G.L. c. 164, sec. 69H. In so doing, the Siting Council evaluates whether a company assesses the relative costs of the various resource options it could use to meet its needs, since options with similar reliability may have different costs and vice versa, and since different load additions with varying gas usage patterns impose different kinds of supply obligations in terms of cost.

North Attleboro has described several steps that it has taken to provide a least cost distribution of its current resources and to pursue appropriate methods to ensure a least-cost energy supply in the future. The Company stated that it uses a linear program to optimize the use of low cost supplies by dispatching these supplies in ascending economical order on a daily and monthly basis (Exh. HO-SP-4). Additionally, the Company asserted that it combined its gas supply planning with planning for Providence Energy Corporation to enhance the Company's ability to purchase low cost gas in the future (Tr. I. p. 18). The Company's witness, Mr. Briden, also stated that North Attleboro is pursuing contracts with interruptible customers to help defray the fixed cost of system supply (Tr. I, p. 18).

Accordingly, the Siting Council finds that North Attleboro has established that its supply plan ensures a least-cost energy supply.

D. Summary

The Siting Council has found that North Attleboro's supply plan is adequate and that it ensures a least-cost energy supply.

Accordingly, the Siting Council hereby APPROVES North Attleboro's supply plan.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the sendout forecast and supply plan of North Attleboro Gas Company as presented in the Fourth Annual Supplement to the Second Long-Range Forecast.

The Siting Council ORDERS North Attleboro in its next forecast filing:

1. (a) to justify the use of different ranges of weather data for its normal year and design year standards, (b) to establish the reliability of its weather databases for North Attleboro's service territory, (c) to justify the use of a methodology for determining its design year standard based on four-day historical peaks, and (d) to justify its projections of customer numbers.

2. (a) to justify the use of a different range of weather data as a basis for its design day standard than that used for its normal year standard, and (b) to justify the appropriateness of its methodology for choosing its design day month.

The Siting Council FURTHER ORDERS North Attleboro to file its next forecast on April 1, 1989.

Frank P. Pozniak
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of March 24, 1988, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Stephen Umans (Public Electricity Member). Absent: Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member); Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard
Chairperson

March 24, 1988
Date

TABLE 1

North Attleboro Gas Company
Forecast of Sendout by Class

Normal Year (BBtu)	1987-88		1990-91	
	Heating	Non-Heating	Heating	Non-Heating
Residential Domestic	94.9	47.1	101.9	50.6
Residential Heating	32.5	8.7	33.5	9.0
Commercial	24.7	22.4	25.4	23.1
Industrial	9.4	9.7	9.7	10.0
Total	161.5	87.9	170.5	92.7

Design Year (BBtu)	1987-88		1990-91	
	Heating	Non-Heating	Heating	Non-Heating
Total	167.2	89.4	176.6	94.2

Design Day (MMBtu)	1987-88	1990-91
Total	1,867	1,975

Source: Exh. HO-SF-3; Exh. C-1, Table G-5

TABLE 2

North Attleboro Gas Company
Base Case Design Day Supply Plan
(MMBTU)

	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:	1,867	1,938	1,957	1,975
RESOURCES:				
Algonquin F-1	814	814	814	814
Algonquin F-2	77	77	77	77
Algonquin F-3	34	34	34	34
Algonquin WS-1	268	268	268	268
Algonquin STB	0	0	0	0
Bay State LNG	1,440	1,440	1,440	1,440
Propane (Storage)	900	900	900	900
TOTAL RESOURCES:	3,476	3,476	3,476	3,476
SURPLUS (DEFICIT):	1,609	1,538	1,519	1,501
RESERVE:	86.2 %	79.4 %	77.6 %	76.0 %

Source: Exh. HO-SP-2

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the)
Commonwealth Gas Company and)
Hopkinton LNG Corporation for)
Approval of the Fourth Supplement to)
the Second Long-Range Forecast of Gas)
Requirements and Resources 1986-91)

EFSC 86-5
EFSC 86-6

FINAL DECISION

Frank P. Pozniak
Hearing Officer

On the Decision:

Brian G. Hoefler
Calvin Young

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby REJECTS the sendout forecast and supply plan filed by Commonwealth Gas Company for the 1986-87 through 1990-91 period.

I. INTRODUCTION

A. Background

Commonwealth Gas Company[1] ("Commonwealth" or "Company"), Massachusetts' second largest local gas distribution company ("LDC"), serves 54 communities in four divisions.[2] In split-year[3] 1985-86, the Company had approximately 207,000 customers, of which about 92.6 percent were residential customers.

Commonwealth's forecast of sendout by customer class for the heating and non-heating seasons[4] is summarized in Table 1 (Exh. C-1, Tables G-1 through G-5). The Company projects an increase in total normalized firm sendout from 36,091 billion British thermal units ("BBtu") in 1986-87 to 40,166 BBtu in 1990-91, representing an annual compound growth rate of 2.7 percent (Exh. C-1, Table G-5).

Hopkinton LNG Corporation ("Hopkinton LNG") is engaged in the operation of liquefied natural gas ("LNG") storage facilities consisting of five above-ground consolidated storage tanks and associated

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1/ Commonwealth Gas Company is a wholly owned subsidiary of the Commonwealth Energy System ("System"), a Massachusetts trust whose other principal operating subsidiaries include Commonwealth Electric Company, Canal Electric Company, and Cambridge Electric Light Company. The System also owns Hopkinton LNG Corporation.

2/ Commonwealth's four divisions are Cambridge (serving 3 municipalities), Framingham (serving 23 municipalities), New Bedford (serving 11 municipalities), and Worcester (serving 17 municipalities) (Exh. HO-50).

3/ A split-year runs from November 1 through October 31.

4/ The heating season is defined as the period from November 1 through March 31. The non-heating season extends from April 1 through October 31.

liquefaction and vaporization equipment located in Hopkinton ("Hopkinton facility") and Acushnet, Massachusetts ("Acushnet facility") (Exh. C-1).[5] Hopkinton LNG does not own or sell gas, but provides natural gas liquefaction, storage, and vaporization services to Commonwealth pursuant to an exclusive 25-year contract terminating in January 1997 (id.).

Commonwealth serves its Worcester division with (1) pipeline deliveries from the Tennessee Gas Pipeline Company ("Tennessee"), (2) LNG dispatched directly into the distribution system from the Hopkinton facility, (3) LNG dispatched indirectly into the distribution system from the Hopkinton facility through Tennessee, and (4) propane from its Worcester propane facility. Commonwealth serves its Cambridge, Framingham, and New Bedford divisions with pipeline deliveries from Algonquin Gas Transmission Company ("Algonquin"). Commonwealth also serves its Framingham division with LNG from the Hopkinton facility and its New Bedford division with LNG from the Acushnet facility.

Commonwealth does not propose to construct or acquire any jurisdictional facilities during the forecast period.

B. History of the Proceedings

On September 15, 1986, Commonwealth and Hopkinton LNG filed their sendout forecast and supply plan ("1986 Forecast"). A Notice of Adjudication was issued by the Hearing Officer on September 22, 1986, directing the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). On October 16, 1986, the Company confirmed publication and notice. There were no intervenors or interested persons in the proceeding.

On May 27 and November 25, 1987, the Energy Facilities Siting Council ("Siting Council" or "EFSC") Staff conducted evidentiary hearings. On December 1, 1987, the Company filed a petition requesting an extension of time for filing responses to record requests made by the

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5/ In future proceedings, the Commonwealth and Hopkinton LNG joint filing will be consolidated into one docket number.

Siting Council at the November 25, 1987 hearing. In that petition, the Company also requested the opportunity to file further written testimony and a brief. On December 3, 1987, the Hearing Officer issued a Procedural Order granting the petition. The Company filed responses to the record requests on December 10, 1987, and filed further written testimony on December 14, 1987. A third evidentiary hearing was held on December 22, 1987.

The Company presented four witnesses: Max A. Gowen, manager of supply planning; Steven H. Bryant, manager of marketing services; Carl Erickson, manager of conservation; and Robert W. Fleck, supply planning analyst. The Siting Council offered 102 exhibits into evidence, largely composed of Commonwealth's responses to information and record requests. The Company presented five exhibits into the record, including the 1986 Forecast and revised tables, which was marked as Exhibit C-1. The Company filed its brief on January 13, 1988.

II. ANALYSIS OF THE SENDOUT FORECAST

A. Standard of Review

As part of its statutory mandate "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, sec. 69H, the Siting Council determines whether projections of gas requirements "are based on substantially accurate historical information and reasonable statistical projection methods." G.L. c. 164, sec. 69J. A forecast that is based on accurate and complete historical data as well as reasonable statistical projection methods should provide a sound basis for resource planning decisions. Berkshire Gas Company, EFSC 86-29, p. 2 (1987).

In its review of a sendout forecast, the Siting Council determines whether a projection method is reasonable according to whether the methodology is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecasting methodology; (b) appropriate, that is, technically suitable for the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is likely to occur. Berkshire Gas Company, EFSC 86-29, pp. 2-3 (1987); Boston Gas Company, EFSC 84-25, p. 8 (1986).

B. Previous Sendout Forecast Conditions

In Commonwealth Gas Company, 14 DOMSC 213, 246 (1986), the Siting Council approved the Company's sendout forecast subject to Conditions Four and Five:[6]

> 4. That Commonwealth justify its use of weather data from its Worcester service territory in calculating normal and design sendout requirements for its other three divisions; or, in the alternative, that it explore and report on the effects on its forecast of using service-territory-specific weather data for each of its four divisions.
>
> 5. That Commonwealth explain and document the source of its assumptions as to average annual use by new residential customers, giving particular attention to why these use assumptions are specifically applicable to each of its four divisions.

In addition, as Condition Six of its previous decision, the Siting Council ordered Commonwealth to comply with its Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95 (1986)[7] and that Order's implementation in Administrative Bulletin 86-1. Commonwealth Gas Company, 14 DOMSC 213, 243-245 (1986).

Commonwealth's compliance with these conditions is discussed in Section II.C and II.D, infra.

6/ The numbers preceding each condition correspond to the numbers assigned in the 1986 decision.

7/ In its Order in EFSC 85-64, the Siting Council established procedures which render its review of the sendout forecasts and supply plans filed annually by each company more effective in carrying out the Siting Council's statutory mandate by promoting appropriate and reliable sendout forecasting and least-cost, minimal-environmental-impact supply planning.

C. Normal Year and Design Year

1. Weather Data

In accordance with its statutory mandate of ensuring a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, the Siting Council is required to review long-range forecasts of gas companies (see G.L. c. 164, secs. 69H, 69I and 69J). An important determinant of a long-range forecast is weather data. The Siting Council reviews weather data as part of a company's weather normalization process, and also as part of a company's forecast of sendout under normal year and design year, as well as design day, conditions. Further, the Siting Council uses these sendout forecasts as a basis for evaluating the adequacy and cost of a company's supply plan. Therefore, for a company to accurately project sendout requirements and plan supply resources under normal year, design year and design day conditions over the forecast period, it is necessary for a company to develop a weather database that ensures a reviewable, appropriate and reliable forecast.

In determining its normal year standard of 6,532 degree days ("DD") (see Sec. II.C.2, infra), and its design year standard of 7,439 DD (see Sec. II.C.3, infra), the Company used its own DD data recorded in the Worcester division during the period from September 1954 to August 1984 ("Worcester weather data") (Exh. C-1, Sec. II, p. 7, Table DD). The Company's derivation of its normal year and design year standards raises a number of issues which are addressed below.

a. Consideration of Effective Degree Days

Commonwealth uses DD as its measure of weather conditions (Tr. II, pp. 14-17). The Company's weather stations generate weather data by recording temperatures on an hourly basis (Tr. II, pp. 29-30). For each of its four divisions, the Company calculates DD by subtracting the average of the 24 hourly temperature readings from 65 (id., p. 29).

The Company's witness, Mr. Gowen, stated that, although Commonwealth has considered using effective degree days ("EDD"), the

Company is not convinced that using EDD would improve its forecast (Tr. II, pp. 15-17, 20-21). However, Mr. Gowen added that, whether or not EDD would improve forecasting, using EDD would be impractical for Commonwealth since it does not have an historical EDD database nor does it presently have reliable wind monitoring equipment at its weather stations (Tr. II, pp. 15, 21-22).

In addressing the possibility that an external source of EDD could be used as the Company's weather database, Mr. Gowen testified that he had studied one such external source, the National Weather Service ("NWS"), and found that the Company's division-specific DD data provided better relationships with sendout than NWS DD data from the same area (id., pp. 16-19).[8] Commonwealth provided Mr. Gowen's study which indicated that, for Commonwealth's four divisions in total, the Company's division-specific data provided better correlations with sendout than NWS data in 41 of 48 cases (Exh. HO-83). Although the study contained no tests of statistical significance, the Company stated that correlation differences in these 48 cases were not always statistically significant (id.). Still, Mr. Gowen stated that the better correlations yielded by the Company's division-specific DD data "leads us to believe that we probably would be introducing additional error" by using EDD from an external source (Tr. II, p. 16).

While the Company has presented a study which demonstrates that internally generated DD data may be superior to external DD data, this study fails to address the question of whether Company-specific EDD data or external EDD data would provide a better indicator of weather than Company-specific DD data. The Siting Council has ordered companies of Commonwealth's size and resources to pursue forecasting enhancements aggressively. See Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95, 104 (1986). In past decisions

8/ In its comparisons, the Company used NWS data collected at Worcester Airport for the Worcester division, at the NWS station in Framingham for the Framingham divsion, at Logan Airport for the Cambridge division, and at the NWS station in New Bedford for the New Bedford division (Exh. HO-83).

regarding the sendout forecasts of large gas companies, the Siting Council has found that one such enhancement is the use of EDD as the primary weather indicator. See Boston Gas Company, EFSC 86-25, p. 9 (1987); Bay State Gas Company, EFSC 86-13, p. 14 (1987).

In the instant case, the Siting Council finds that the issue of whether Commonwealth should use EDD requires further study. Although the Company has argued persuasively that use of EDD data is impractical at this time, the Siting Council notes that the Company has not studied potential near-term and long-term forecasting methodology improvements which might result from the use of EDD -- whether from an internal or external source -- as the primary weather indicator.

Still, for purposes of this review, the Siting Council finds that the use of DD, as opposed to EDD, as the indicator of weather, is appropriate. However, the Siting Council ORDERS Commonwealth to present in its next forecast filing (a) an analysis of potential sendout forecasting improvements that may result from the use of EDD, (b) an analysis of the costs that would be incurred if the Company were to collect EDD, and (c) an analysis of the feasibility of using an external EDD source while internal EDD data are collected.

b. Range of Weather Data

The Worcester weather data extends for a 30-year period, from August 1954 to September 1984. Commonwealth does not have a systematic policy for periodically updating this weather database (Tr. II, p. 37).

For the purposes of this review, the Siting Council finds that the 30-year range of the Worcester weather data is appropriate. However, the Siting Council ORDERS Commonwealth in its next filing to develop a systematic methodology for updating its range of weather data.

c. Worcester Weather Data

i. Description

To determine normal year, design year and design day standards used in forecasting sendout requirements in its four divisions, the

Company used the Worcester weather data (Exh. C-1, Sec. II, p. 7). In Condition Four of its previous decision, the Siting Council required Commonwealth to justify its use of Worcester weather data for sendout forecasts for each division, or to explore and report upon the use of division-specific weather data.

The Company opted to provide justification for its continued use of Worcester weather data to forecast sendout for each division (Exh. C-1, Sec. II, p. 7). In support of its use of Worcester weather data, the Company stated that (1) the weather data for its other divisions are incomplete and not necessarily reliable, and (2) Worcester DD data are highly correlated with divisional DD data (id.).

The Company reviewed the weather databases for its Framingham, Cambridge and New Bedford divisions over the same 30-year period as its Worcester weather data, and concluded that those three divisional weather databases were not reliable. The Company provided that, for the Framingham division, weather data were collected at two different locations;[9] for the Cambridge division, the weather database is missing four or six years of data; and, for the New Bedford division, weather data were collected at different locations and different methodologies were used to calculate DD (Exhs. HO-4, HO-54; Tr. II, pp. 23-35). Mr. Gowen testified that Commonwealth now is collecting consistent, reliable weather data in all four divisions (Tr. II, pp. 26-27, 35).

Regarding the correlation of Worcester DD to divisional DD, Commonwealth compared R-squared statistics of daily Worcester DD and each division's daily DD using data collected during the 17 heating season months from November 1983 through December 1986 (Exhs. HO-51, HO-54).[10] The comparison showed that DD in the Worcester division are generally similar to DD in the Cambridge, Framingham, and New Bedford

9/ Until 1974, the Framingham division's DD were recorded in Framingham; since 1974, the DD have been recorded in Southborough (Exh. HO-54).

10/ These R-squared statistics measured the correlation between Worcester DD and divisional DD.

divisions.

The Company also compared R-squared statistics from daily sendout versus daily DD regressions based on Worcester DD with R-squared statistics from daily sendout versus daily DD regressions based on divisional DD for 17 heating season months from November 1983 through December 1986 (Exhs. HO-51, HO-54, HO-66).[11] The comparison of R-squared statistics provide an indication of which weather database, either Worcester weather data or division-specific weather data, tends to be better correlated with historical divisional sendout.

The comparisons showed that, for the Framingham division, using Framingham DD data resulted in better correlations than Worcester DD data in only 1 of the 17 heating season months; for the Cambridge division, using Cambridge DD data resulted in better correlations than using Worcester DD data in 13 of the 17 heating season months; for the New Bedford division, using New Bedford DD data resulted in better correlations than using Worcester DD data in 15 of the 17 heating season months (id.). The Company stated that none of these R-squared differences are significant (Exhs. HO-54, HO-95), although the Company did not test their statistical significance (Tr. III, p. 117).

ii. Analysis

Commonwealth argues that a recent decision of the Massachusetts Department of Public Utilities ("MDPU") in Commonwealth Gas Company, D.P.U. 87-32 (December 31, 1987) requires the Siting Council to find that the use of Worcester weather data for all of the Company's

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11/ The Company provided R-squared statistics using both division-specific and Worcester DD for the heating season months from November 1977 through December 1986 (Exhs. HO-66, HO-82). However, the Company was unable to deduct daily interruptible sales from total daily sales for split-years 1977-78 through 1982-83 (Exh. HO-65). Therefore, in evaluating the Company's firm sendout forecast, the Siting Council does not consider R-squared statistics for the period 1977-78 through 1982-83.

divisions is appropriate (Company Brief, pp. 4-5).[12] However, the Siting Council notes that the purpose of the MDPU's review of weather data is distinctly different from that of the Siting Council. The MDPU evaluates a company's use of weather data to ensure that the load data used to adjust actual test-year revenues, allocate costs, and design rates reasonably reflect normal conditions (see Commonwealth Gas Company, D.P.U. 87-32, p. 30 (December 31, 1987)), whereas the Siting Council reviews weather data as part of a company's weather normalization process, and also as part of a company's forecast of sendout under normal year and design year, as well as design day, conditions. Consequently, the MDPU's acceptance of the Worcester weather data does not require an identical finding in this proceeding.

The Company maintains that it is taking steps to obtain reliable division-specific data (Company Brief, p. 6). However, the Company argues that at this time, reliable or complete weather databases are not available for the Framingham, Cambridge, and New Bedford divisions (id., pp. 5-6). Hence, the Company asserts that it has justified the continued use of the Worcester weather data as the best available source (id., pp. 4-7).

Based on the record, the Siting Council finds that Commonwealth's use of the Worcester weather data to forecast sendout requirements in the Worcester and Framingham divisions is appropriate and reliable.

For the Cambridge division, the record shows that Cambridge weather data is missing four or possibly six years of data leaving the Company with a 24- or 26-year weather database for that division. At the same time, Mr. Gowen stated that, even though it uses a 30-year Worcester weather database, some other time period such as 20 or 25 years would provide an acceptable weather database (Tr. II, pp. 37-41). Although Mr. Gowen stated that he believes "it would be invalid to use a different 30-year period for one division versus the other[s]" (Tr. II, p. 27), the Company provided no basis or statistical support for this

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12/ In response to a request of the Company (Company Brief, p. 5), the Siting Council hereby takes administrative notice of Commonwealth Gas Company, D.P.U. 87-22 (December 31, 1987).

statement.[13] Therefore, the Siting Council finds that the Company has failed to establish that a reliable or complete division-specific weather database was not available for the Cambridge division.

In recent cases involving Commonwealth, the Siting Council has raised questions regarding the Company's use of Worcester weather data for sendout forecasts for each division. Commonwealth Gas Company, 14 DOMSC 213, 224, 246 (1986); Commonwealth Gas Company, 11 DOMSC 171, 183-184 (1984). In the 1986 decision, the Siting Council ordered Commonwealth to justify the use of Worcester weather data for sendout forecasts for each division. Commonwealth Gas Company, 14 DOMSC 213, 224, 246 (1986).

In the instant case, the Company has failed to justify the continued use of Worcester weather data for the sendout forecast for the Cambridge division. Accordingly, the Siting Council finds that the Company has failed to establish that using Worcester weather data to forecast sendout requirements for the Cambridge division is appropriate and reliable.

The Company has raised several questions about the integrity and completeness of its New Bedford weather database. In particular, the Company asserted that its New Bedford weather database is not reliable because the data were recorded at different locations and the methodology for calculating DD differs from that used in its other divisions. However, the record is unclear as to whether these assertions are valid, if so how data reliability is affected, and hence whether the Company has reliable division-specific weather data for the New Bedford division.

Accordingly, the Siting Council finds here that the use of Worcester weather data to forecast sendout requirements for the New Bedford division is minimally appropriate and reliable. At the same time, however, the Siting Council notes that further information

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13/ The Company's witness was asked on two separate occasions if weather data collected prior to 1954 could be used as a substitute for the missing four to six years of data (Tr. II, p. 27). On both occasions, the witness responded by stating that it is important to maintain consistent databases (id., pp. 27-28).

regarding the reliability of New Bedford-specific weather data is required. Therefore, the Siting Council ORDERS Commonwealth (a) to provide a complete analysis of the availability and reliability of New Bedford-specific weather data, and (b) to justify any continued use of Worcester weather data for forecasting sendout requirements in the New Bedford division.

d. Conclusions on Weather Data

The Siting Council has found that the use of DD, as opposed to EDD, is appropriate, and that the 30-year range of the Worcester weather data is appropriate. The Siting Council has found that use of Worcester weather data to forecast sendout requirements for its Worcester, Framingham and New Bedford divisions is appropriate and reliable. The Siting Council has also found that Commonwealth has failed to establish that using Worcester weather data to forecast sendout requirements for the Cambridge division is appropriate and reliable.

Accordingly, the Siting Council finds that Commonwealth has complied with Condition Four in regard to justifying the use of Worcester weather data for the Worcester and Framingham divisions, and failed to comply with Condition Four in regard to providing sufficient justification of the use of Worcester weather data in the Cambridge division.

2. Normal Year Standard

To determine its normal year standard, the Company first calculated DD for twelve normal months by averaging the total DD in the respective months for the 30 years contained in the Worcester weather database (Exh. C-1, Table DD, EFSC Exh. 1).[14] The Company then summed these twelve normal months to derive its normal standard of 6,532 DD (id.).

14/ The documents marked as "EFSC Exhibits" refer to documents provided by Commonwealth as part of Exhibit C-1.

The Siting Council finds that the Company's methodology for determining its normal year standard is reviewable and appropriate. Since the Siting Council found in Section II.C.1.c.iii, supra, that using Worcester weather data to forecast sendout requirements in the Worcester, Framingham and New Bedford divisions is appropriate and reliable, the Siting Council also finds that the normal year standards for the Worcester, Framingham and New Bedford divisions are reliable.

However, since the Siting Council found in Section II.C.1.c.iii, supra, that Commonwealth failed to establish that using Worcester weather data to forecast sendout requirements for the Cambridge division is appropriate and reliable, the Siting Council also finds that the Company has failed to establish that its normal year standard for the Cambridge division is reliable.

3. Design Year Standard

In its most recent decision regarding Commonwealth, the Company was ordered to comply with the Siting Council's Decision in Docket No. 85-64. The Siting Council's Decision in EFSC 85-64 notified gas companies that renewed emphasis would be placed on design criteria "to ensure that those criteria bear a reasonable relationship to design conditions that are likely to be encountered." Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95, 97 (1986). The Siting Council ordered each company, in each forecast filing, to include a detailed discussion of how and why it selected the design weather criteria that it uses, giving particular attention to the frequency with which design conditions are expected to recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan. Id., pp. 96-97, 104-105. Further, in past decisions the Siting Council has found that the largest gas companies in Massachusetts must consider tradeoffs between reliability and cost in establishing design standards. Boston Gas Company, EFSC 86-25, pp. 12-15 (1987); Bay State Gas Company, EFSC 86-13, pp. 16-18 (1987).

a. Description

Commonwealth plans for a design year of 7,349 DD, representing the coldest 12-month period, September 1955 to August 1956, in the 30-year Worcester weather database (Exh. C-1, Sec. II, p. 9, Table DD; Exh. HO-6). Commonwealth provided that, since its design year occurred once in the Company's 30-year weather database, the recurrence expectancy is once in 30 years (id.; Exh. HO-86). Commonwealth noted that "It is difficult to predict the probability of a design year occurring when one uses a methodology such as the one Commonwealth uses" (Exh. HO-6).

In regard to the gas supply cost implications of its choice of the design year standard, Commonwealth claimed that a different design year criterion would not have a significant impact on the cost of gas for firm customers (Exh. HO-6). In support of this claim, Commonwealth repeatedly asserted that its most recent gas supply decisions were based upon a need to obtain firm peak day capacity and thus were unaffected by the Company's design year standard (Exhs. HO-6, HO-31, HO-38; Tr. I, pp. 63, 123, 132-133, 149). In addition, the Company provided analyses demonstrating that it has ample supplies to meet design year sendout requirements (Exhs. HO-35, HO-36).

b. Analysis

In support of its design year standard, the Company has argued that the design year standard is based on the coldest 12-month period in its 30-year weather database. Knowing the source and basis of the Company's design year standard is necessary to understand the methodology used to determine it; however, for a large company such as Commonwealth this information alone does not give sufficient attention to the frequency with which design conditions are expected to occur.

Commonwealth claimed that, since its design year standard is based on the coldest 12-month period in its 30-year weather database, the standard has a recurrence expectancy of once in 30 years. This estimate of the recurrence expectancy is incorrect since the methodology for determining it is invalid. The Company's methodology assumes that each DD level in the Company's 30-year weather database has a discrete recurrence expectancy equal to the inverse of the number of years in the database. Such an assumption ignores (1) the variation of probabilities about the mean (e.g., a DD level close to the mean is more likely to occur than one more distant from the mean), and (2) the fact that the Company's 30-year weather database is a sample of a population and therefore does not contain all possible DD levels (e.g., a DD level which did not occur during the database, such as the Company's normal year standard of 6,532 DD, could still occur). The resultant problem is that the Company's methodology depends not only on the number of years chosen for the sample, but also on the particular years which happen to be chosen. Such dependence leads to instability in both the recurrence expectancy and the design year standard. For instance, when the Company increased the number of years in its range of weather data from 25 to 30 but did not change the year of DD data it chose as the design year standard (Tr. II, pp. 41-43), the Company's recurrence expectency automatically changed from once in 25 years to once in 30 years.[15] If the Company instead had chosen to maintain a 25-year database by adding the most recent five years of data and dropping the earliest five years (which would have included dropping the year in which 7,349 DD occurred), this methodology still would have maintained a recurrence expectency of once in 25 years while the design year standard changed from 7,349 DD to about 7,056 DD (Exh. HO-86).

Thus, the Siting Council finds that Commonwealth has failed to establish that its methodology for determining the recurrence expectancy of its design year standard is based on reasonable statistical projection methods.

In addition, Commonwealth provided no indication of when it would reassess its design year standard in order to determine whether it continues to be appropriate and reliable. In fact, Mr. Gowen testified that in 1984 Commonwealth extended its previous weather database from 25 years to 30 years to enable the Company to retain its design year

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15/ The Company identified this particular problem as one of the difficulties inherent in its recurrence expectancy calculation methodology (Exh. HO-6).

standard (Tr. II, pp. 41-43). The implications of this step are problematic in that the Company failed to reassess the level of reliability of its design year standard prior to the database extension. In the past, the Siting Council has criticized methodologies for determining design criteria which failed to manage the level of reliability maintained by such criteria. Boston Gas Company, EFSC 86-25, p. 13 (1987). The record in this proceeding indicates that Commonwealth has set its 7,349 DD design year standard as a benchmark rather than as a level of reliabilty; that is, DD determines reliability rather than reliability determining DD. Thus, the Siting Council finds that the Company has failed to establish that it manages the level of reliability maintained by its design year standard.

Therefore, the Siting Council finds that Commonwealth has failed to establish that its design year standard bears a reasonable relationship to design conditions that are likely to be encountered.

The Company has argued that its design year standard does not impose any significant supply costs. In support, Commonwealth has established that the short-run incremental cost of its design year standard is negligible. Arguably, a design criterion with negligible incremental cost is optimal since reliability improvements have been or may be obtained at virtually no cost. However, short-run incremental cost impacts may be only one piece of an analysis of the reasonableness of a design year standard, since long-run changes in the Company's load shape or supply mix still could result in significant costs associated with design year planning.[16] In that Commonwealth provided no analysis of long-run costs, the Siting Council cannot accept the Company's argument that its design year standard imposes no significant supply costs, especially in the long run.

Based on the foregoing, the Siting Council finds that Commonwealth has not demonstrated that its methodology for determining its design year standard is appropriate or reliable.

16/ Commonwealth's sendout forecast indicates plans to add load which would result in changes in load shape (see Section II.C.4.a.iii, infra). In addition, the Company plans to modify its supply mix (Tr. II, pp. 139-162; see Section III.C, infra).

4. Forecast Methodologies

a. Description

Based on its normal year standard, Commonwealth forecasted normal year sendout requirements for split-years 1986-87 through 1990-91 by projecting use by existing customers and load growth for each division by customer class (Exh. C-1, Sec. I, pp. 1-13). The Company's customer classes consist of residential heating and non-heating customers, commercial customers and industrial customers. The Company used the same methodology to forecast design year sendout except that the forecast is based on the Company's design year standard (id.).

The Company's forecasts of normal year and design year sendout requirements are summarized in Table 1.

i. Existing Customers

To forecast monthly sendout for existing load under normal and design conditions for each division, Commonwealth projected monthly sendout as a linear function of DD (Tr. I, p. 13). For the normal year, the Company projected monthly firm sendout by totalling projected monthly baseload and normalized heating load (Exh. C-1, Sec. I, pp. 1-2, EFSC Exhs. 1, 3-6). Commonwealth projected monthly baseload by averaging firm sendout for July and August 1985, and projected monthly normalized heating load by normalizing monthly firm heating sendout as a linear function of DD for the period from April 1985 through March 1986 ("base period") (id.).

Commonwealth projected monthly design sendout for each division similarly except that it multiplied normalized monthly firm heating load factors by the number of DD in a design year.

Although Commonwealth used a linear model to specify the relationship between sendout and DD, Mr. Gowen acknowledged that the relationship is not perfectly linear (Tr. II, p. 137; see also Tr. I, pp. 12-14, Tr. II, pp. 154-157, Tr. III, pp. 113-116). Mr. Gowen stated that the Company conducted statistical checks which indicated that sendout per DD increases at higher DD levels (Tr. I, p. 12). However, Mr. Gowen added that the relatively high R-squared statistics of its linear sendout/DD regressions supported use of a linear model as a reasonable approximation of the relationship between sendout and DD (Tr. III, pp. 115-116). He speculated that unexplained sendout, ranging from 4 to 45 percent of total sendout, could be the result of sendout being lower on weekends and holidays (Tr. II, pp. 138-139; Tr. III, pp. 116, 120-121; Exh. HO-1), variation in industrial sendout from day to day (Tr. III, p. 116), and difficulty in factoring out interruptible sendout from the raw data (id., p. 119). In addition, Mr. Gowen testified that Commonwealth did not consider a non-linear specification of the sendout/DD relationship because the Company had no theoretical basis to postulate any particular relationship (Tr. II, pp. 140-146).

Next, Commonwealth allocated projected monthly firm sendout under normal and design conditions to its existing residential, commercial and industrial customer classes by developing baseload and heating load allocation factors for each of these customer classes, and multiplying such factors by projected monthly firm sendout (Exh. C-1, Sec. I, pp. 3-5, EFSC Exhs. 2, 6).

The Company projected firm sendout for its existing customers for the normal year and design year by totalling projected firm sendout for each of the twelve months in the base period, and applying this total to each year of the forecast period. Commonwealth reduced its projection of firm sendout for normal year and design year by one percent per year to account for conservation (Exh. C-1, Sec. I, p. 3). The Company stated that it has not done a detailed study that justifies the one percent per year conservation factor, and that this conservation adjustment is a historical practice based upon judgment (Tr. I, p. 10; Exh. HO-11).

The Company maintains that it has reported on the status of its conservation monitoring program to the Siting Council, and that it is currently compiling a useful database from Commonwealth's newly implemented conservation programs (Company Brief, p. 12). However, the Company maintains that, at this time, there is not yet sufficient data to warrant departure from the one percent conservation assumption (id., p. 13).

Commonwealth was unable to quantify the impact of changes in fuel prices or economic activity upon the projection of firm sendout for the normal year or design year (Exhs. HO-3, HO-5, HO-21; Tr. I, pp. 54-56; see also Tr. II, pp. 101-131). Commonwealth added that its current forecast methodology "has the limitation of not giving adequate attention to changes in demand from existing customers" (Exh. C-2, p. 8).

ii. Load Growth

The Company also forecasted sendout associated with load growth in its residential sector, commercial sector,[17] and industrial sector (Exh. C-1, Sec. I, p. 8). Commonwealth stated that its load growth forecasts for all three market sectors were premised on certain assumptions about economic activity and fuel prices (Exh. C-1, Sec. I, pp. 7-8). In particular, the Company assumed that (1) the economy will remain healthy throughout the five-year forecast period, and (2) over the long run, gas will remain competitive with distillate fuels but non-competitive with residual oil (id.). Commonwealth stated that market conditions and fuel prices are too difficult to forecast over an extended period of time such as a five-year forecast period (id.; Tr. II, pp. 117). The Company acknowledged, however, that the level of economic activity is very important (Tr. II, pp. 117-119).

For the purposes of forecasting residential heating customers' load growth, the Company disaggregated the class into conversions, new homes and new condominiums (Exh. C-1, Sec. I, pp. 8-12, EFSC Exhs. 7-13). Commonwealth assumed that all new residential customers would be heating customers, and that its existing residential non-heating customer class would diminish over the forecast period due to conversions to gas heat (Exh. HO-16; see also Exh. C-1, Table G-2).

The Company based its forecast of load growth for new homes and condominiums on a database which tracks new home and condominium construction activity in the residential sector, and on information

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17/ The Company's projection of load growth for the municipal customer class is included in the projection of load growth for the commercial class (Tr. III, p. 141).

provided through direct contact with the development and business communities (Exh. HO-87; Tr. II, pp. 120-122).[18] Company representatives canvass sources such as construction sites and town halls to collect database information such as the number of housing units planned or under construction and construction schedules (Exh. C-1, Sec. I, p. 9, EFSC Exh. 28; Exh. HO-87). In addition, the Company interviewed a sample of builders to ascertain their expectations about future construction (Exh. HO-87; Tr. II, pp. 118-119). Mr. Gowen noted that the Company evaluated the information gathered and, in certain cases, adjusted it based on various factors, including the Company's experience with particular developers (Tr. II, pp. 90-92). Commonwealth reported that preliminary analysis indicates that housing under construction, particularly near mains, is a good predictor of new residential customer growth (Exh. HO-87; Tr. I, p. 53).

The Company based its forecast of load growth for commercial and industrial sectors on a database which tracks load addition requests for new structures and existing facilities, and on information provided through direct contact with development and business communities (Exh. HO-88; Tr. II, pp. 120-121; Tr. III, pp. 136-141). The Company collected information on building types, end-use equipment, and expected dates that new load would materialize (Exh. HO-88; Tr. III, p. 139). Commonwealth also interviewed selected commercial and industrial customers (Exh. HO-88). Mr. Gowen stated that the commercial and industrial database along with Company contacts with the "prime movers" in the business and development communities, captured such factors as economic activity, fuel prices, GNP, and interest rates (Tr. II, pp. 120-121). The Company stated that after considering all of its sources of information, Company personnel must apply their judgment and experience in forecasting load growth associated with residential,

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18/ The Company's witness, Mr. Bryant, noted that Commonwealth is developing a database containing information on prospective residential customers which will be "an inventory by address of residential structures located on the Company's mains or easily reached by the Company's mains that are not currently served by gas" (Tr. III, pp. 136-137).

commercial and industrial markets (Exhs. HO-87, HO-88).

Thus, based on information in the databases and interviews with developers and public officials, the Company projected load growth for the first two forecast years for new homes and condominiums and for the commercial and industrial markets (Exh. C-1, Sec. I, pp. 8-9; Exhs. HO-87, HO-88). During the remainder of the forecast period, the Company relies on extrapolation for projecting added loads (Exh. C-2, p. 8; see also Tr. III, pp. 139-140).

iii. Consideration of Other Models

Commonwealth's witness, Mr. Bryant, testified that the Company intends to reevaluate its gas demand forecasting methodology (Tr. III, p. 6). To facilitate this reevaluation, the Company will employ a consultant to conduct a feasibility study and make recommendations regarding an appropriate forecasting methodology for Commonwealth, particularly for forecasting the third through fifth years of the forecast period (id., pp. 6-10, 14, 133-136). Mr. Bryant testified that the consultant will consider the suitability of econometric and end-use models and methods for incorporating conservation into the forecast (id.). Nonetheless, the Company maintains that considerable evidence has been presented in this proceeding supporting the continued use of its forecasting methodology (Company Brief, pp. 9-11).

b. Analysis

In past decisions, the Siting Council has reviewed Commonwealth's forecast methodology. See, e.g., Commonwealth Gas Company, 14 DOMSC 213, 219-230 (1986); Commonwealth Gas Company, 11 DOMSC 171, 179-201 (1984). The Company asserts that the Siting Council has previously approved its forecast methodology in the 1986 decision (Company Brief, p. 9).

Companies are required to file forecasts with the Siting Council that are based on substantially accurate historical information and reasonable statistical projections. G.L. c. 164, sec. 69J. In determining whether a statistical projection method is reasonable, the

Siting Council may consider the size of the company, the state of art of forecasting, and the extent to which the forecast methodology requirements of 980 CMR 7.00 are met. See 980 CMR 7.02 (9)(b)(2). Therefore, forecast filings must be reviewed to ensure that such forecasts meet or continue to meet the requirements of both statute and regulations, and are or continue to be appropriate and reliable.

i. Previous Conditions

(A) Condition Five

In response to requirements in Condition Five of the last decision, Commonwealth explained and documented the source of its assumptions regarding average annual use per new residential customer and considered the applicability of any assumptions to each of its four divisions (Exh. C-1, Sec. I, pp. 7-12, Sec. II, p. 8, EFSC Exhs. 7-13).

Accordingly, the Siting Council finds that Commonwealth has complied with Condition Five.

(B) Condition Six

As part of Condition Six of the last decision, the Siting Council ordered Commonwealth to recalculate historical sendout requirements based on the Siting Council's new November 1 through October 31 split-year, to file Table FA, and to describe in detail and justify its methodology for weather normalizing sendout data. Commonwealth Gas Company, 14 DOMSC 213, 243-244 (1986).

Based on the record, the Siting Council finds that Commonwealth has complied with all portions of Condition Six except the requirement to justify its weather-normalization methodology. See Section II.C.4.b.ii, infra.

ii. Existing Customers

Commonwealth's methodology for forecasting use by existing customers raises two primary issues: (1) whether the Company adequately considered the effects of weather by specifying a linear relationship between sendout and DD, and (2) whether the Company's methodology gives adequate attention to changes in use by existing customers.

In support of its linear specification, the Company argued that specifying a non-linear relationship was impractical, and that the linear specification provided a "reasonable" approximation of the relationship between sendout and DD.

The Siting Council rejects the Company's assertion that a non-linear specification is impractical. During the course of the proceeding, the Company claimed that it had explored the use of a piece-wise linear regression but determined that there were insufficient data to use it (Tr. II, pp. 155-157). Still, the Company provided that its heating factors varied from month to month (id., p. 156) indicating that the underlying problem is not simply that the Company cannot stratify its data for DD ranges. Instead, the problem is that the Company has already stratified the data once (by month), and does not want to stratify it again. Further, the Company failed to consider alternatives to piece-wise regression such as a regression based on the entire year's sendout data with months and DD ranges specified as binary predicting variables (id., pp. 155-157; Tr. III, pp. 114-115). Practical and theoretically preferable alternatives to a linear model may well exist which the Company failed to consider. Finally, the Company claimed it did not have a theoretical basis for specifying a particular non-linear relationship over any others. If adequate theoretical work is not available, then Commonwealth should develop its own empirical relationship.[19]

Regarding the Company's second argument, that its linear model provided a reasonable approximation of the relationship between sendout and DD, Commonwealth provided statistical indicators of a strong linear relationship between sendout and DD (Tr. II, p. 141). However, the reasonableness of Commonwealth's linear model's results must be judged

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19/ In the past, the Siting Council has criticized forecast methodologies which failed to adequately consider methods to account for data non-linearity. Boston Gas Company, EFSC 86-25, p. 29 (1987).

by whether sendout projections would be significantly improved by accounting for the non-linear relationship between sendout and DD data, or for other relevant factors (such as correcting for interruptible load or for variations in use on weekdays versus weekends and holidays) that may impact sendout projections. Commonwealth provided no basis or documentation for determining which factors, if considered and analyzed, would significantly improve the Company's forecasting capability. Further, Commonwealth did not demonstrate that it explored a reasonable set of explanations or data transformations to find the most suitable model specification. Although Commonwealth's linear model raises several concerns which the Siting Council expects the Company to address in its next forecast, for purposes of this review the Siting Council accepts the Company's argument that the linear model provided a reasonable approximation of the relationship between sendout and DD.

Commonwealth suggested that its forecasting methodology has the limitation of not giving adequate attention to changes in use by existing customers. Several aspects of the Company's methodology support this suggestion. For instance, while Commonwealth admits that changes in economic activity and fuel prices affect use by existing customers, it did not explicitly include these factors in its forecast arguing that economic activity and fuel prices are too difficult to predict. However, in this proceeding, the Company has failed to demonstrate that economic activity and fuel prices are too difficult to predict. The Siting Council notes that in reviews of both gas and electric forecasts, the Siting Council has evaluated methodologies that have incorporated economic activity and/or fuel prices in forecasts as a routine matter. See Bay State Gas Company, EFSC 86-12 (1987); Bay State Gas Company, 14 DOMSC 143 (1986); Eastern Utilities Associates, 14 DOMSC 41 (1986); Cambridge Electric Light Company, 12 DOMSC 39 (1985); Massachusetts Electric Company, 12 DOMSC 197 (1985); Boston Edison Company, 10 DOMSC 203 (1984); Northeast Utilities, 11 DOMSC 1 (1984).

The Company also has failed to justify the adjustment in its sendout forecast for conservation trends. The Company has failed to present any analysis which supports the conservation adjustment factor which reduces existing customers' use by one percent per year. In past decisions the Siting Council questioned the appropriateness of the

Company's judgmental conservation adjustments. Commonwealth Gas Company, 14 DOMSC 213, 223 (1986); Commonwealth Gas Company, 11 DOMSC 171, 198-201 (1984); Commonwealth Gas Company, 9 DOMSC 332, 371-376 (1983). Further, in a case where a company failed to justify its use of a conservation adjustment, the Siting Council found that the company's sendout forecast was neither appropriate nor reliable. Berkshire Gas Company, EFSC 86-29, pp. 9-10 (1987).

In light of the Company's failure to adequately consider the effects on sendout of economic activity, fuel prices, and conservation, the Siting Council finds that Commonwealth has failed to establish that its methodology for determining use by existing customers for a normal year and design year is appropriate.

iii. Load Growth

The Company asserted that, by directly monitoring potential load growth activity, its methodology for forecasting new home and condominium load growth and commercial and industrial load growth for the first two years of the forecast period captured the dynamics of economic activity and fuel prices within its service territory. While the Company also stated that the forecast of load growth involves some application of judgment by Company management, the Siting Council notes that the Company's judgment consisted of evaluating quantitative factors (e.g., construction schedules, end-use equipment heating inputs) to determine load growth for the first two forecast years. The Siting Council accepts the Company's assertion that, for the first two forecast years, this methodology captures the effects on load growth of economic activity and fuel prices by closely monitoring growth markets.

For the final three years of the forecast period, however, Commonwealth's forecast is simply an extrapolation of the first two years. Commonwealth provided no support or documentation for its assumptions that the factors affecting load growth in its market will remain constant over all five years of the forecast period. In light of Mr. Gowen's testimony that the three to five year time frame of the forecast period drives Commonwealth's supply planning decisions (Tr. II, p. 107), it is critical for Commonwealth to develop a forecast that is based on reasonable statistical projections.

Accordingly, the Siting Council finds that Commonwealth has established that its methodology for forecasting load growth in these markets is reviewable and appropriate for the first two years of the forecast period, but has failed to establish that it has an appropriate methodology for the last three years of the forecast period.

In regard to residential conversions, the record indicates that the Company used its "considerable experience" for projecting load growth (Tr. I, p. 53). However, the Company has not demonstrated that historical data were used as the basis of its projection. Accordingly, the Siting Council finds that the Company has failed to establish that its methodology for forecasting load growth for residential conversions is appropriate.

Finally, based on the record, the Siting Council finds that Commonwealth has established that its methodology for forecasting residential non-heating customer load growth is reviewable and appropriate.

On balance, the Siting Council finds that Commonwealth has failed to establish that its methodology for forecasting load growth is appropriate.

c. Conclusions on Forecast Methodologies

The Siting Council has found that Commonwealth (1) failed to establish that its methodology for determining use by existing customers for a normal year and design year is appropriate, and (2) failed to establish that its methodology for forecasting load growth is appropriate. Accordingly, the Siting Council finds that the Company's forecasting methodologies for normal year and design year are not appropriate.

During the course of the proceeding, the Company indicated its intention to retain a consultant to conduct a feasibility study and make recommendations regarding an appropriate forecasting methodology for Commonwealth. The Siting Council ORDERS the Company to provide in its next filing (a) a copy of the consultant's feasibility study and recommendations regarding an appropriate forecasting methodology for

Commonwealth, and (b) an indication of whether, and if so how, the Company intends to implement all such recommendations.

5. Conclusions on Normal Year and Design Year

The Siting Council found that the Company has complied with (1) Condition Four in regard to justifying the use of Worcester weather data for the Worcester and Framingham divisions, and failed to comply with Condition Four in regard to providing sufficient justification of the use of Worcester weather data in the Cambridge division, (2) Condition Five, and (3) all portions of Condition Six except for the requirement that the Company justify its methodology for weather normalizing data.

The Siting Council found that the Company's methodology for determining its normal year standard is reviewable and appropriate. The Siting Council also found that the normal year standards for the Worcester, Framingham and New Bedford divisions are reliable, but that the Company has failed to establish that the normal year standard for the Cambridge division is reliable. Further, the Siting Council found that the Company's forecast methodology for the normal year is not appropriate. Accordingly, the Siting Council finds that Commonwealth's forecast of normal year sendout requirements is neither appropriate nor reliable.

The Siting Council found that the Company's methodology for determining its design year standard is neither appropriate nor reliable. The Siting Council also found that the Company's forecast methodology for the design year is not appropriate. Accordingly, the Siting Council finds that Commonwealth's forecast of design year sendout requirements is neither appropriate nor reliable.

D. Design Day[20]

1. Weather Data

Commonwealth identified weather as the primary factor for determining its design day standard and for projecting design day requirements (Exh. C-1, Sec. I, pp. 4-5). To determine its design day standard of 70 DD, the Company used the 30-year Worcester weather database collected from September 1954 through August 1984 (id., p. 7).

The Company's derivation of its design day standard raises three issues: (1) whether use of DD instead of EDD is appropriate; (2) whether the use of a 30-year range of weather data is appropriate; and (3) whether use of Worcester weather data to determine the design day standard for the Worcester, Framingham, Cambridge, and New Bedford divisions is appropriate and reliable (see Sec. II.C.1, supra).

The Siting Council previously found that Commonwealth's use in this proceeding of DD, as opposed to EDD, as its indicator of weather is appropriate (see Section II.C.1.a, supra). The Siting Council also found that the 30 years of Worcester weather data is appropriate (see Section II.C.1.b, supra). In addition, the Siting Council found that (1) use of Worcester weather data to forecast sendout for the Worcester, Framingham and New Bedford divisions is appropriate and reliable, and (2) the Company failed to establish that use of Worcester weather data to forecast sendout for the Cambridge division is appropriate and reliable (see Section II.C.1.c.iii, supra). These findings apply to the design day sendout forecast as well as to the normal year and design year sendout forecasts.

2. Design Day Standard

In its most recent decision regarding Commonwealth, the Company was ordered to comply with the Siting Council's Decision in Docket No.

20/ For purposes of this review, the Siting Council uses "design day" and "peak day" synonymously.

85-64. The Siting Council's Decision in EFSC 85-64 notified gas companies that renewed emphasis would be placed on design criteria "to ensure that those criteria bear a reasonable relationship to design conditions that are likely to be encountered." Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95, 97 (1986). The Siting Council ordered each company, in each forecast filing, to include a detailed discussion of how and why it selected the design weather criteria that it uses, giving particular attention to the frequency with which design conditions are expected to recur, and to the effect of the design standard on the reliability of the company's forecast and the cost of its supply plan. Id., pp. 96-97, 104-105. Further, in past decisions, the Siting Council has found that the largest gas companies in Massachusetts must consider tradeoffs between reliability and cost in establishing design standards. Boston Gas Company, EFSC 86-25, pp. 12-15 (1987); Bay State Gas Company, EFSC 86-13, pp. 16-18 (1987).

a. Description

Commonwealth plans for a design day of 70 DD for all four divisions, representing the coldest day experienced in the 30 years of Worcester weather data plus one additional DD[21] (Exh. C-1, Sec. II, p. 9, Table DD; Exhs. HO-6, HO-67). Commonwealth initially provided that the recurrence expectancy of a 70 DD day is once in 30 years (Exh. C-1, Table DD). However, the Company modified its position:

> Although the recurrence probability for the design [day] criterion can not be directly calculated from the Company's data, it is clear that the probability is substantially less than 1/15 [once in 15 years] (6.67%). It is probably on the order of 1% [once in 100 years]. (Exh. HO-67)

21/ If division-specific weather data were used, the design day standard would be 67 DD in Cambridge, 71 DD in Framingham, and 62 DD in New Bedford (Exh. HO-84).

In support of its design standard of 70 DD, the Company asserted that it used a standard "more conservative" than the coldest actual occurrence because the Company understands the variability inherent in predicting design day sendout requirements (Exh. HO-6). Mr. Gowen asserted that the more conservative standard was justified because of the high cost of having a design day capacity deficiency and the low short-term incremental cost of LNG, its marginal gas supply (Tr. II, pp. 71, 75-76, 227-230; see Exh. C-2, p. 7).

Regarding the circumstances under which the Company would reevaluate its design day standard, Mr. Gowen testified that the Company would undertake a cost/benefit study if substantial costs would be incurred in meeting its design day standard (Tr. II, p. 228). The witness stated that an appropriate time to have reevaluated the design day standard may have been when the Company replaced Algonquin synthetic natural gas ("SNG") volumes with Algonquin F-2, F-3 and F-4 volumes (id., pp. 74-75).

While Mr. Gowen testified that the Company is aware of the cost implications of its design day standard and considered such costs in selecting the 70 DD standard, he acknowledged that costs were not explicitly considered (id., pp. 71, 227, 229-230). Mr. Gowen stated that the most recent supply increments added to meet design day requirements were annual gas supplies including the F-2, F-3 and F-4 contracts (Tr. I, p. 149; Tr. II, pp. 72-74).

b. Analysis

In support of its design day standard, the Company has argued that the design day standard is based upon one DD over the coldest DD experienced in 30 years. Knowing the source and basis of Commonwealth's design day standard is necessary to understand the methodology used to determine it; however, for a large company such as Commonwealth this information alone does not give sufficient attention to the frequency with which design conditions are expected to occur.

The Company stated that the recurrence expectancy of its design day standard falls in a range of once in 30 years to once in 100 years. However, Commonwealth provided no discernible methodology for determining the recurrence expectancy of its design day standard. Therefore, the Siting Council finds that Commonwealth failed to establish that its methodology for determining the recurrence expectancy of it design day standard is based on reasonable statistical projection methods.

While Mr. Gowen asserted that the Company would reevaluate its design day standard if the need arose, the Company provided no indication of when it would do so. In the past, the Siting Council has criticized methodologies for determining design criteria which failed to manage the level of reliability maintained by such criteria. Boston Gas Company, EFSC 86-25, p. 13 (1987). Thus, the Siting Council finds that Commonwealth has failed to establish that it manages the level of reliability maintained by its design day standard.

Therefore, the Siting Council finds that Commonwealth has failed to establish that its design day standard bears a reasonable relationship to design conditions that are likely to be encountered.

In addition, the Company argued that the high cost of having a design day capacity deficiency and the low short-term incremental cost of its marginal gas supply justifies the Company's "more conservative" design day standard. However, the Company has not provided an analysis of the incremental cost associated with its design day standard, nor has it shown that the incremental cost of its design day standard is low. Further, the Company has failed to provide an analysis of the long-run cost implications of its design day standard. Therefore, the Siting Council cannot accept the Company's argument that the high cost of design day capacity deficiency and low cost of its marginal gas supply justifies the reliability level specified by its design day standard.

Accordingly, the Siting Council finds that Commonwealth has not demonstrated that its methodology for determining its design day standard is appropriate or reliable.

3. Forecast Methodology

Based on its design day standard, Commonwealth forecasted design day sendout requirements for split-years 1986-87 through 1990-91 for each division by projecting use by existing customers (including an adjustment for conservation) and load growth (Exh. C-1, Sec I, pp. 1-13). The design day sendout forecast for each division is summarized in Table 3.

To determine its divisional design day sendout requirements, the Company used the divisional monthly baseload and heating load factors that were derived for projecting sendout for normal year and design year (see Section II.C.4.a.i, supra). Commonwealth multiplied the monthly heating load factors by the design day standard, 70 DD, and added daily baseload to calculate the highest daily sendout for the base period (Exh. C-1, Sec. I, pp. 3-5; Tr. III, pp. 110-111).[22] The Company compared the highest daily sendout to an estimated design day sendout derived by a regression of sendout as a linear function of daily DD for each heating season month in the base period (Exhs. C-4, C-5). The sendout difference was used by the Company to adjust the highest daily sendout to arrive at the projection of design day sendout in each division for the forecast period (Exhs. C-4, C-5; Exhs. HO-37, HO-51, HO-54).

In its review of the Company's normal year and design year forecasting methodologies (see Section II.C.4.c, supra), the Siting Council found that Commonwealth (1) failed to establish that its methodology for determining use by existing customers for a normal year and design year is appropriate, and (2) failed to establish that its methodology for determining load growth is appropriate. These findings apply to the Company's forecast methodology for the design day as well.

Accordingly, the Siting Council finds that Commonwealth failed to establish that its design day forecast methodology is appropriate.

4. Conclusions on Design Day

The Siting Council found the use of DD, as opposed to EDD, is appropriate, and that the 30-year range of the Worcester weather data is

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22/ The Company provided that the month in which highest daily sendout occurred would be its design day month for the entire forecast period (Exh. C-1, EFSC Exhs. 3-7).

appropriate. The Siting Council also found that the use of Worcester weather data to forecast sendout requirements for its Worcester, Framingham and New Bedford divisions is appropriate, and that the Company has failed to establish that using Worcester weather data to forecast sendout requirements for the Cambridge division is appropriate.

The Siting Council found that the Company's methodology for determining the design day standard is neither appropriate nor reliable. The Siting Council also found that the Company failed to establish that its design day forecast methodology is appropriate.

Accordingly, the Siting Council finds that Commonwealth's forecast of design day sendout requirements is neither appropriate nor reliable.

E. Summary

In summary, the Siting Council finds that the Company's forecasts of normal year, design year and design day sendout requirements are neither appropriate nor reliable.

Accordingly, the Siting Council hereby REJECTS Commonwealth's forecast of sendout requirements.

III. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate "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, sec. 69H, the Siting Council has traditionally reviewed three dimensions of every utility's supply plan: adequacy, reliability, and cost. Berkshire Gas Company, 14 DOMSC 107, 128 (1986); Holyoke Gas and Electric Light Department, 15 DOMSC 1, 27 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 54 (1986); Westfield Gas and Electric Light Department, 15 DOMSC 67, 72 (1986); Fall River Gas Company, 15 DOMSC 97, 111 (1986). While the Siting Council has broadly defined adequacy as the Company's ability to meet projected normal year, design year, peak day, and cold-snap firm sendout requirements with sufficient reserves, the changing character of the gas market and an increasing reliance upon new gas projects that have been subject to delay and cancellation require the Siting Council to review adequacy both in terms of a company's base plan and its contingency plan.[23] Berkshire Gas Company, EFSC 86-29, p. 17 (1987).

Therefore, in order to establish adequacy, a gas company must demonstrate that it has an identified set of resources to meet its projected sendout under a reasonable range of contingencies. If a company cannot establish that it has an identified set of resources to meet sendout requirements under a reasonable range of contingencies, the company must then demonstrate that it has an action plan to meet projected sendout in the event that the identified resources will not be available when expected. Id.

23/ In the past, the Siting Council has reviewed the adequacy of a gas company's supply plan in the event that certain existing resources become unavailable. Boston Gas Company, EFSC 84-25, p. 33 (1986); Fitchburg Gas and Electric Light Company, 15 DOMSC 39, 53 (1986); Fall River Gas Company, 15 DOMSC 97, 115 (1986); Berkshire Gas Company, 14 DOMSC 107, 127 (1986); Bay State Gas Company, 14 DOMSC 143, 168 (1986); Essex County Gas Company, 14 DOMSC 189, 201-202 (1986).

In adopting an expanded definition of adequacy for gas companies, the Siting Council notes that it is no longer necessary to make specific findings regarding the reliability of a company's resource plan. Instead, through review of a company's base plan, under a reasonable range of contingencies and, if necessary, an action plan, the Siting Council has developed an adequacy standard which incorporates concerns regarding the reliability of a company's supply plan. Id., p. 18.

The Siting Council also reviews the cost of a utility's supply plan in terms of cost minimization, subject to trade-offs with adequacy of supplies. Id.

The Siting Council recognizes that a company's supply planning process is continuous, and that some balance is always required between the adequacy, cost, and environmental impacts of different supply sources. The Siting Council also recognizes that a company's supply options are affected by conditions existing or expected to exist in its market area and by supplies available in the region. Thus, each company's supply plan will be different, and the Siting Council recognizes the unique factors affecting the particular company under review. The Siting Council reviews each company's basis for selecting a supply alternative, or the company's decisionmaking process which led it to select that supply alternative, to ensure that the company's decisions are based on projections founded on accurate historical information and sound projection methods. Berkshire Gas Company, 14 DOMSC 107, 128 (1986).

B. Previous Supply Plan Conditions

In Commonwealth Gas Company, 14 DOMSC 213, 246 (1986), the Siting Council approved Commonwealth's supply plan subject to the following three conditions:

> 1. That Commonwealth provide in its Fourth Supplement a detailed discussion of the status of its conservation monitoring program including computerization of data, the impact of conservation (as opposed to economic factors) on sales, and conservation patterns during the year and on peak days. The Company shall also report the results of its customer usage survey to the Siting Council as they become available.

2. That Commonwealth state in its Fourth Supplement its expectations regarding the future availability and reliability of the Boston Gas storage and LNG contracts, with particular attention to the status of transportation arrangements with Algonquin Gas Transmission Company for delivering the gas to Commonwealth's Cambridge division.

3. That Commonwealth discuss in its Fourth Supplement the means which are currently in place to transfer volumes of gas from Framingham to Cambridge in excess of the Cambridge division's MDQ on the Algonquin system.

In addition, as Condition Six of its previous decision, the Siting Council ordered Commonwealth to comply with its Order in Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities, EFSC 85-64, 14 DOMSC 95 (1986) and that Order's implementation in Administrative Bulletin 86-1. Commonwealth Gas Company, 14 DOMSC 213, 243-245 (1986).

Commonwealth's compliance with these conditions is discussed in Sections III.C and III.D, infra.

C. Adequacy of Supply

In reviewing Commonwealth's current supply plan, the Siting Council must determine whether the Company has adequate resources to meet projected sendout requirements under a reasonable range of contingencies. In order to make this determination, the Siting Council examines whether the Company's "base case" resource plan is adequate (1) to meet firm sendout requirements under normal year, design year, design day, and cold snap weather conditions, and (2) to meet those firm sendout requirements under a reasonable range of supply contingencies. Berkshire Gas Company, EFSC 86-29, p. 22 (1987).

Although the Siting Council previously found that the Company's forecasts of normal year, design year, and design day sendout requirements were not appropriate or reliable (see Sections II.C and II.D, supra), those forecasts serve as the only available bases for evaluating the Company's supply preparedness, and therefore the Siting Council considers these forecasts in its review of supply adequacy.

1. Evaluation of Base Case Resources

In order to determine whether a gas company's base case resource plan is adequate, the Siting Council must first determine if that company can reasonably rely on each resource in its base case to meet its sendout requirements during the forecast period.

a. Pipeline Gas and Storage Services

i. Existing Deliveries and Services

Commonwealth receives deliveries of pipeline supplies and storage gas from Algonquin and Tennessee (Exh. C-1, Table G-24). Algonquin delivers firm gas and provides storage services under rate schedules F-1, F-2, F-3, F-4, WS-1, and STB (id.). Algonquin also provides storage services and interruptible storage transportation under rate schedule SS-III (Tr. II, p. 171). Tennessee delivers firm gas and provides storage services under rate schedule CD-6 (Exh. C-1, Table G-24). Commonwealth also has an agreement with Consolidated Gas Supply Corporation ("Consolidated") for underground storage services under the GSS rate schedule (id.; Exh. HO-43). Tennessee provides firm transportation of gas stored at Consolidated facilities under the FSST-NE rate schedule (id.). The maximum daily quantities ("MDQ") and annual volumetric limitations ("AVL") under these contracts are summarized in Table 2.

Commonwealth's F-1, F-4, and WS-1 contracts with Algonquin expire during the forecast period (Exh. C-1, Table G-24). The Company stated that it expects Algonquin to continue delivering F-1, F-4, and WS-1 volumes, or to provide replacement volumes, after the contracts expire[24] (Tr. II, p. 159-162). The Company also noted that Algonquin has begun discussions regarding the restructuring of Algonquin's supply

24/ Pursuant to Section 7(b) of the Natural Gas Act of 1936 (15 U.S.C.A., Section 717f(b)), Algonquin must obtain Federal Energy Regulatory Commission approval to abandon these services (see Exh. HO-59).

contracts with Commonwealth (id.).

Finally, Commonwealth reported that the Federal Energy Regulatory Commission ("FERC") approved the abandonment of Algonquin's SNG service (Exh. C-1, Sec. I, p. 13).

Accordingly, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on its full contractual volumes under rate schedules F-1, F-2, F-3, F-4, WS-1, STB, CD-6, GSS, and FSST-NE throughout the forecast period.

ii. Planned Deliveries and Services[25]

Commonwealth's supply plan indicated that new pipeline services would begin during the forecast period. First, during the 1986-87 heating season, the Company implemented an arrangement with Tennessee for interruptible backhaul transportation of up to 30 BBtu/day[26] from the Hopkinton facility through Tennessee's pipeline system to Commonwealth's Worcester division ("Tennessee backhaul") (Exhs. HO-56, HO-90). Second, Commonwealth stated that it planned to implement an arrangement known as the "Marathon project" with Algonquin for firm transportation of 40 BBtu/day from the Hopkinton facility through Algonquin's pipeline system to the Cambridge, Framingham, and New Bedford divisions beginning in the 1988-89 heating season (Exhs. HO-37, HO-55, HO-61).

(A) Tennessee Backhaul

Commonwealth included an interruptible contract with Tennessee in its design day supply plan for the Worcester division. In the past, the

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25/ The Company's initial filing reflected its participation in Tennessee's AVL expansion project (Exh. C-1, Sec. I, pp. 14). However, when Tennessee withdrew its AVL expansion application at FERC and substituted the NOREX project (Exh. HO-31; Tr. I, pp. 61-63), Commonwealth elected to withdraw the AVL expansion from its supply plan (Tr. I, p. 65).

26/ For purposes of this review, the Siting Council assumes that 1 BBtu is equivalent to 1 MMCF.

Siting Council has not accepted interruptible service arrangements in design plans (see, Boston Gas Company, EFSC 86-25, p. 57 (1987)). In the instant case, the Company asserted that there are certain characteristics associated with the Tennessee backhaul service that warrant reconsideration of the Siting Council's position in this particular instance. The Siting Council analyzes the Company's assertions to determine whether characteristics of the Tennessee backhaul service allow Commonwealth to reasonably rely upon it for base case planning purposes.

(1) Description

(a) Contracts

Tennessee and Commonwealth executed two contracts under which Tennessee provides Commonwealth with interruptible transportation service from Commonwealth's Hopkinton gate station located on Tennessee's main transmission line ("mainline"), along the mainline and Tennessee's Worcester lateral ("Worcester lateral"), to Commonwealth's Worcester gate station located on the Worcester lateral (Exhs. HO-56, HO-97).[27]

27/ In theory, a backhaul is the movement of gas against normal pipeline flow which, in Tennessee's mainline in the Worcester lateral area, is in an easterly direction (Exh. HO-98). In the case of the Tennessee backhaul, gas would flow west in the mainline from Tennessee's Hopkinton gate station to the junction of the mainline and the Worcester lateral (id.). In contrast, a forward haul is where gas moves with normal pipeline flow. In the case of the Tennessee backhaul, gas flow in the Worcester lateral is a forward haul (Exhs. HO-75, HO-96).

In actuality, however, normal pipeline flow is not changed by a backhaul. Instead, a backhaul is a displacement of gas where additional gas volumes are taken at an upstream point, here at the Worcester lateral junction, and replaced downstream, here at the Hopkinton gate station. Gas flow remains the same both upstream of the Worcester lateral junction and downstream of the Hopkinton gate station, but decreases between the two points.

While gas flow upstream of the Worcester lateral junction and downstream of the Hopkinton gate station remain the same, pressures do not. Pressures increase thereby providing benefits to the operation of Tennessee's gas pipeline operation (Tr. II, p. 174). In this proceeding, Commonwealth provided no analysis of the magnitude of pressure increase resulting from the Tennessee backhaul.

On September 4, 1986, Tennessee and Commonwealth executed a precedent agreement for interruptible transportation service of 30 BBtu/day for a term expiring on November 1, 2000 (Exh. HO-56). On October 7, 1986, pursuant to Section 7(c) of the Natural Gas Act, Tennessee filed with FERC an application for a certificate of public convenience and necessity ("certificate") authorizing Tennessee to perform interruptible transportation service for Commonwealth in accordance with the terms of the precedent agreement ("7(c) contract") (Exhs. HO-38, HO-56, HO-60). In its order of December 24, 1986, FERC issued a limited-term certificate authorizing interruptible transportation of up to 30 BBtu/day for a period of two years from the date of the Order (Exh. HO-38).[28] On November 19, 1987, Tennessee and Commonwealth executed the 7(c) contract (Exh. HO-97).[29]

On December 3, 1986, Tennessee announced its intent to begin providing open access transportation for its customers pursuant to FERC Order 436 on December 10, 1986 (Exh. HO-38). In March 1987, Tennessee signed a contract with Commonwealth for such transportation service ("436 contract") (Exh. HO-56; Tr. I, pp. 96-97).[30] The 436 contract is a two-year agreement with an "evergreen clause" automatically extending the contract on a month-to-month basis until, upon 30 days notice, one of the parties terminates the contract (Exh. HO-56). Mr. Gowen asserted that, since Tennessee now operates pursuant to FERC Order 436 and therefore cannot deny transportation access, "the whole concept of termination of that type of a contract [436 contract] is almost

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28/ Tennessee has appealed this Order to the D.C. Circuit Court of Appeals (Tr. III, p. 32). Besides contesting FERC's limitation of the term of the interruptible transportation service to two years, Tennessee is also contesting FERC's denial of recovery of fuel charges for the transportation service (Tr. I, p. 99; Tr. III, pp. 32-33; see also Exh. HO-38).

29/ Although the contract provides that the period of interruptible transportation service extends to November 1, 2000, the FERC certificate limits the contract term to December 24, 1988.

30/ Pursuant to the 436 contract, modest volumes of gas were delivered in the Worcester division during the 1986-87 heating season through the backhaul arrangement (Tr. I, p. 182).

irrelevant" (Tr. I, pp. 97-98).

Mr. Gowen indicated that the Company's 7(c) contract would have priority over any 436 interruptible agreements Tennessee may have with other customers for service off the Worcester lateral (Tr. III, pp. 31-34). In addition, he testified that the Company's 436 contract has priority over other 436 interruptible agreements Tennessee might or will have with other customers for service off the Worcester lateral due to the timing of Commonwealth's request for such service and the "first-come-first-served" nature of Tennessee's 436 transportation arrangements (Tr. III, p. 34).[31]

Finally, both the 7(c) and 436 contracts provide for interruptible transportation by Tennessee of up to 30.0 BBtu/day from the Hopkinton facility to the Worcester division (Exhs. HO-37, HO-60).[32]

(b) Reliability of Service

Commonwealth provided the following assessment of reliability of the three components of the Tennessee backhaul arrangement -- the Worcester lateral, the mainline, and Commonwealth's injection into the mainline at the Hopkinton facility:

> Tennessee has told the Company that the [Worcester] lateral which serves the Worcester station is capable of handling the increase

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31/ Mr. Gowen noted, however, that FERC Order 436 has changed a number of times since it was first implemented (Tr. III, pp. 79-80), and that certain FERC initiatives could alter Tennessee's priority scheme thereby altering the Company's 436 contract priority status (id., pp. 34-35). He further stated that the case pending before the D.C. Circuit Court of Appeals could affect various 7(c) and 436 transportation priority arrangements (Tr. III, pp. 77-80).

32/ Although the record does not indicate that the 7(c) and 436 contracts are mutually exclusive or otherwise limited to a total of 30 BBtu/day, Commonwealth indicated no intention to use its Tennessee backhaul arrangements at a rate above 30 BBtu/day. Thus, the Siting Council considers the MDQ of the joint backhaul agreements to be 30 BBtu/day.

> of 30,000 dth [MMBtu] per day. The rest of the transportation is a backhaul. As long as the LNG plant is capable of injecting regasified LNG vapor into the Tennessee mainline, the transportation is available. (Exh. HO-75; see also Tr. I, p. 125; Tr. II, pp. 172-175)

The Worcester lateral extends about 5.62 miles within the Worcester division from the mainline to Upland Street in the City of Worcester (Exhs. HO-50, HO-98; Tr. II, p. 172). The Company noted that no other LDC takes gas off the Worcester lateral (Tr. III, p. 24). Commonwealth noted that the Worcester lateral component of the Tennessee backhaul arrangement is a forward haul (Exhs. HO-75, HO-96). Thus, to ensure reliable service, the Worcester lateral must have enough capacity to carry Tennessee backhaul volumes in addition to other firm design day volumes. Commonwealth stated that Tennessee indicated it has the capacity in the Worcester lateral to deliver the Tennessee backhaul volume of 30 BBtu/day above Commonwealth's firm contractual volumes of CD-6 (55.386 BBtu/day) and FSST-NE (8.286 BBtu/day), which are also delivered through the Worcester lateral (Exh. HO-96; see also Tr. III, pp. 22-23).

Regarding the possibility of Tennessee providing transportation service to an end-user via the Worcester lateral, Mr. Gowen indicated that transportation for customers similar in size to Commonwealth's largest industrial customers in the Worcester area, at about 3-4 BBtu/day, would not impede Commonwealth's ability to take the full Tennessee backhaul volumes in the Worcester division (Tr. III, p. 25). He added that the most likely large end-users would be entities producing electrical generation such as electric utilities and independent cogenerators, although Commonwealth expects no large new end-users on the Worcester lateral (Tr. III, pp. 26-27, 46-47).

If a large end-user requested interruptible transportation service on the Worcester lateral, Mr. Gowen indicated that the service would most likely be provided pursuant to FERC Order 436 (Tr. III, pp. 31-34). Mr. Gowen added that Commonwealth would have priority over the end-user in that Commonwealth already has a 436 contract (Tr. III, p. 34). If a large end-user requested firm transportation service on the Worcester lateral, Mr. Gowen stated that the Company would intervene at

FERC to protect its interests (id., p. 26).

With respect to the mainline component of the Tennessee backhaul arrangement, Mr. Gowen noted that since normal gas flow in the mainline is east, gas physically does not have to be transported from Worcester to Hopkinton, which would be a westerly flow (Tr. II, pp. 172-175).

In discussing the Company's ability to inject gas into the mainline at the Hopkinton facility, Mr. Gowen noted that with the Tennessee backhaul and Marathon arrangements, the LNG dispatch capability at the Hopkinton facility would be approximately 170 BBtu/day of vaporization (Tr. II, p. 238). This falls within the Company's preferred vaporization rate of 180 BBtu/day, and within the ultimate vaporization constraint of 240 BBtu/day (Tr. II, pp. 81-82, 173; see Section III.C.1.b, infra). Mr. Gowen also indicated that Hopkinton facility vaporizers can inject gas into the mainline consistent with Tennessee's requirements (Exh. HO-97; Tr. II, p. 180). Mr. Gowen noted that, since the Hopkinton facility was designed and built by Tennessee as its own peak shaving supply, the vaporizers were designed for the specific purpose of injecting gas into the mainline (Tr. I, p. 168; Tr. III, p. 178).[33] Mr. Gowen indicated that no other operational constraints exist at the Hopkinton facility which would prevent the injection of LNG into Tennessee's system (Tr. II, pp. 173, 185-186). He added that

> the only circumstances that I can see where the service would be interrupted would be a [force majeure] situation on Tennessee's pipeline system, which basically cut off all the deliveries of gas to the Worcester area, in which case we wouldn't be just worried about the backhaul volumes, we would be worried about the 55 [BBtu/day] that would be going through that [lateral] anyway. (Tr. II, p. 184)

While the Tennessee backhaul contracts do not specify the circumstances under which Tennessee would interrupt service, Mr. Gowen

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33/ Commonwealth Energy System bought the Hopkinton facility from Tennessee in the late 1960s (Tr. II, p. 235).

testified that Tennessee provided its assurance to Commonwealth that the service is essentially firm subject to the Company's ability to inject vaporized LNG from the Hopkinton facility into the mainline (Exhs. HO-56, HO-97; Tr. II, pp. 173-188).

Finally, Mr. Gowen pointed out that Tennessee itself benefits from the backhaul arrangement since Commonwealth increases the pressure on Tennessee's system (Tr. II, p. 174; see also Tr. II, p. 196; Exh. C-2, pp. 3-4). He also noted that the Company had provided such benefits to Tennessee during a supply emergency in 1981 when the Company injected gas into the mainline (Tr. III, p. 178).

In sum, the Company argues that although the contract provides for interruptible transportation service and does not specify the situations in which interruption would be allowed, it is the understanding of the parties that the service would be essentially firm, subject only to extreme scenarios such as the inability of the Hopkinton facility and events of force majure (Company Brief, p. 23). The Company also argues that the potential shortage of transportation capacity due to new loads on the Worcester lateral is purely speculative at this time (id., p. 24). Thus, the Company maintains that the Tennessee backhaul arrangement is reliable (id.).

(2) Analysis

The Siting Council discusses the reliability during peak service conditions of each component of the Tennessee backhaul agreement -- the Worcester lateral, the mainline, and Commonwealth's injection into the mainline -- and the likelihood that Tennessee would interrupt transportation service.

The Company has shown that Tennessee has the capacity in the Worcester lateral to provide the additional service of 30 BBtu/day. However, the Worcester lateral raises another reliability question -- whether any other party could displace the interruptible transportation service provided to Commonwealth. Although the 7(c) contract expires on December 24, 1988, the Company has demonstrated that Tennessee's implementation of FERC Order 436 provides a mechanism for transporting backhaul volumes throughout the forecast period. At this time, the

Company's 7(c) and 436 contracts provide Commonwealth with the highest priority of interruptible transportation service on the Worcester lateral. However, while interruptible transportation requests of other parties will not displace Commonwealth's interruptible agreements, firm requests could. Therefore, an issue which we must consider is the potential of any party to compete with Commonwealth for that capacity.

Since Commonwealth has the only gate station off the Worcester lateral and in fact the lateral is entirely within the Worcester division, Commonwealth notes that the loads most likely to affect transportation on the Worcester lateral would be from electric utilities or cogenerators. The Siting Council agrees that development of such new loads on the Worcester lateral is speculative at this time. Accordingly, for the purposes of this review, the Siting Council accepts the Company's assertion that under peak conditions the Worcester lateral has sufficient capacity to provide Tennessee backhaul service. The Siting Council ORDERS Commonwealth to provide in its next forecast filing a complete analysis of the effects on capacity of the Worcester lateral of any potential third party transportation or supply.

The only question regarding the reliability of the mainline component is whether it is indeed a backhaul. The record demonstrates that normal gas flow in the mainline is east while, in theory, the Tennessee backhaul transports gas west. Although the Company did not fully analyze the effects on flow and pressure in the mainline for the Tennessee backhaul, and for certain existing and potential pipeline/supply projects,[34] for purposes of this review, the Siting Council accepts the Company's assumption that during peak conditions the Tennessee backhaul is indeed a backhaul in the mainline. The Siting Council ORDERS Commonwealth to provide in its next forecast filing a complete analysis of design day flow and pressure in Tennessee's mainline considering the effects of the Tennessee backhaul, Granite State Gas Transmission Company's Portland Pipeline project, and

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34/ During this proceeding, two existing projects were identified that may affect flow and pressure in Tennessee's mainline: Granite State Gas Transmission Company's Portland Pipeline project and Distrigas of Massachusetts Corporation's LNG imports (Tr. III, p. 30).

Distrigas of Massachusetts Corporation's LNG imports in addition to any future projects expected to materialize within the five-year forecast period.

Regarding Commonwealth's ability to inject gas into the mainline, the record demonstrates that Commonwealth has the ability to do so at any time that its LNG plant is in operation. In fact, the Hopkinton facility was designed as a peak shaving source for Tennessee and Commonwealth has provided peak shaving service on at least one occasion. Further, the Hopkinton facility has no identified operational constraints that would prevent dispatch at rates of up to 170 BBtu/day. Accordingly, Commonwealth has shown that it has the ability to inject gas into the mainline during peak flow conditions.

Although Commonwealth has established that Tennessee has the capacity to provide the backhaul service during peak conditions, the Siting Council recognizes that the 7(c) and 436 contracts may be interrupted at Tennessee's sole discretion. However, Commonwealth has shown that it can reasonably rely on Tennessee during peak conditions, and that it has been assured by Tennessee that backhaul service would not be interrupted as long as Commonwealth can inject gas into Tennessee's system at the Hopkinton facility. In fact, since Commonwealth's injection raises Tennessee's system pressures, the Tennessee backhaul service benefits Tennessee, particularly during peak conditions. Of course, a force majeure situation might prompt a service interruption, but such an interruption could occur pursuant to a firm or interruptible contract.

In summary, Commonwealth has established that, during peak conditions, it has the ability to inject gas into the mainline, and both the mainline and Worcester lateral components of the Tennessee backhaul have sufficient capacity to provide Tennessee backhaul service.

Accordingly, for the purposes of this review, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on the Tennessee backhaul throughout the forecast period.

(B) Marathon Project

Beginning November 1, 1988, Algonquin plans to provide firm transportation of up to 40 BBtu/day during the heating season from the Hopkinton facility to the Cambridge, Framingham, and New Bedford divisions (Exh. HO-61). To provide this service, Algonquin proposes to construct an eight-mile, 12-inch lateral connecting the Hopkinton facility to Algonquin's main transmission line (id.). In effect, the Marathon project would permit an indirect dispatch by Commonwealth of 40 BBtu/day from the Hopkinton facility to the Cambridge (14 BBtu/day), Framingham (21 BBtu/day), and New Bedford (5 BBtu/day) divisions (Exh. HO-55). Additionally, during the non-heating season, the Marathon project would allow delivery on an interruptible basis of Commonwealth's F-1, F-2, F-3, and F-4 supplies to the Hopkinton facility for liquefaction and storage (Exh. HO-61).

Accordingly, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on the Marathon project beginning November 1, 1988.

b. Liquefied Natural Gas

The Company purchases storage services from its affiliate, Hopkinton LNG, at the Hopkinton and Acushnet facilities (Exh. C-1, Table G-14). The Hopkinton and Acushnet facilities provide storage capacities of 3,000 BBtu and 500 BBtu, respectively (id.).

Hopkinton LNG refills its storage tanks at the Hopkinton facility during the non-heating season by liquefying pipeline gas provided by Commonwealth at a rate of up to 16.5 BBtu/day (Exh. C-1, Tables G-22; Exh. HO-7). To refill the storage tanks at the Acushnet facility, Commonwealth trucks LNG from the Hopkinton facility during the non-heating season (Tr. II, p. 158). If necessary, Commonwealth has the ability to replenish supplies at the Acushnet facility by trucking during the heating season (id.).

In addition, Commonwealth contracts for vaporization services from Hopkinton LNG at a maximum vaporization rate of 240 BBtu/day (Exh. C-1, Sec. I, p. 14). But while the Hopkinton facility has four 60 BBtu/day vaporizers (id.), Commonwealth considers one of these vaporizers to serve as backup for the other three (Tr. II, pp. 81-82).

The Company's distribution system restricts LNG dispatch capability from the Hopkinton facility to a total of 99.6 BBtu/day -- 46.8 BBtu/day directly into the Framingham division and 52.8 BBtu/day directly into the Worcester division (Exh. HO-37). With the Tennessee backhaul arrangement increasing Commonwealth's dispatch capability from the Hopkinton facility by 30.0 BBtu/day (id.), and the proposed Marathon project increasing LNG dispatch capability from the same facility by 40.0 BBtu/day (Exh. HO-71), the total LNG dispatch capability of the Hopkinton facility will be 169.6 BBtu/day.

Accordingly, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on a dispatch capability for the Hopkinton facility of 99.6 BBtu/day without the Tennessee backhaul and Marathon project, 129.6 BBtu/day with the Tennessee backhaul but without the Marathon project, and 169.6 BBtu/day with the Tennessee backhaul and the Marathon project.

The Acushnet facility has three vaporizers, each with capacities of 10 BBtu/day, used to dispatch LNG into the New Bedford division (Exhs. HO-37, HO-91; Tr. III, pp. 95-97). Mr. Gowen testified that the Acushnet facility has never had operational problems limiting the reliability or availability of the facility (Tr. III, pp. 95-97).

Accordingly, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on a dispatch capability for the Acushnet facility of 30 BBtu/day throughout the forecast period.

c. Propane[35]

Commonwealth has a propane facility in Worcester which has a storage capacity of 31 BBtu (Exh. C-1, Table G-14). Commonwealth can dispatch 14.4 BBtu/day of propane from this facility into the Worcester division (Exh. C-1, Table G-14; Exh. HO-37).

To rely on the Worcester propane facility as a long-term supply,

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35/ In a previous filing, Commonwealth indicated an intent to retire its Cambridge propane facility. Commonwealth Gas Company, 11 DOMSC 171, 211 (1984). The Company provided that the Cambridge propane facility was retired and noted that the facility cannot be reactivated (Tr. II, pp. 158-159).

the Company provided that safety and operating systems require substantial capital improvements (Exh. HO-73). Thus, Commonwealth indicated that, if the D.C. Court of Appeals extends the 7(c) contract with Tennessee to the year 2000 or finds that the 436 contract is as reliable as the 7(c) contract, the Company might retire the Worcester propane facility at some point during the forecast period (Exh. HO-38; Tr. I, pp. 150-151; Tr. III, pp. 76-81).

Accordingly, the Siting Council finds that Commonwealth can reasonably rely for base case planning purposes on a dispatch capability for the Worcester propane plant of 14.4 BBtu/day throughout the forecast period.

2. Conservation and Load Management

In 1986, the Massachusetts legislature amended the Siting Council's statute to require the Siting Council to approve a company's long-range forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. In the past, the Siting Council has limited its review of gas company conservation and load management ("C&LM") efforts to cost minimization issues. Here the Siting Council expands its review to determine whether the Company can demonstrate that it has reasonably considered C&LM as resource options to help ensure that it has adequate supplies to meet projected sendout requirements.

a. Description

Commonwealth has participated in MASS/SAVE's residential conservation program, completed a pilot residential conservation program, and developed a pilot conservation program for non-profit/charitable institutions (Exh. C-1, Sec. II, pp. 1-2).

The Company's Gopher Gas Conservation Program ("Gopher Gas Program") was a pilot project installing $100 of weatherization materials in approximately 5,000 households (Exh. HO-46). The Company conducted a study of its Gopher Gas Program with respect to energy savings (id.). For residential heating customers, the study indicated (1) a gross savings of $109.53 per heating season for an investment of about $100, (2) an average reduction in use per customer of 18.6 percent within one heating season, and (3) an investment pay-back period of less than one year (id.). In total, the Gopher Gas Program reduced gas usage by 78.4 BBtu within one heating season (id.; Exh. HO-94). Commonwealth found that the Gopher Gas Program produced annualized savings of about $354,359 at a cost to the Company of $504,230 (Exh. HO-94).

Commonwealth has received approval from Massachusetts Executive Office of Energy Resources ("EOER") for a proposal to expand the Gopher Gas Program to cover approximately 36,000 households (Exh. HO-48). The Company's witness, Mr. Erickson, stated that the Company expects an energy savings of about 15.6 MMBtu per residential customer from the expanded Gopher Gas Program (Tr. III, p. 68).

The Company's Operation Heat Save Program will provide non-profit and charitable institutions with up to $1,500 in weatherization services (Exh. HO-47). The program had 197 participants and was completed in October, 1986 (id.).

At this time, the Company stated that it has not included any MMBtu gas savings from its conservation programs in its supply plan because the savings from its existing conservation programs are relatively small (Tr. I, pp. 20-22; Tr. II, p. 224). However, the Company stated that it has retained a consultant to make recommendations regarding how to consider MMBtu gas savings from its conservation programs in its forecast (Tr. III, p. 69).

Regarding load management, Mr. Gowen stated that Commonwealth has not implemented any time-of-day load management programs because they are inappropriate for gas utilities, but noted that the Company's interruptible rates represent a seasonal type of load management program (Tr. II, pp. 223-225). However, Mr. Bryant asserted that the Company's intent is to examine the cost/benefit relationships of conservation and load management compared to other incremental supply options (Tr. III, p. 71).

b. Analysis

i. Condition One

In Condition One of its last decision, the Siting Council required Commonwealth (1) to discuss the status of its conservation monitoring program, including the computerization of data, impact on sales, and annual and peak sendout reductions, and (2) to report the results of the customer usage survey.

Commonwealth described its involvement with MASS/SAVE's residential energy audit program, its MASS/SAVE commercial energy audit proposal, its proposal before EOER to extend the Gopher Gas Program, and its Operation Heat Save Program, and also provided an analysis concerning the sales and sendout impacts of the Gopher Gas Program.

Accordingly, the Siting Council finds that Commonwealth has complied with Condition One.

ii. C&LM as a Resource Option

The Company is only at the beginning stages of an effort to identify C&LM opportunities that could help the Company ensure adequate supplies to meet its firm customers' sendout requirements in a least-cost manner. Since the Company did not include C&LM as a base case resource, the Siting Council makes no findings here regarding whether the Company's supply planning process included an adequate consideration of C&LM.[36]

3. Normal Year and Design Year Adequacy

In normal year and design year planning, Commonwealth must have adequate supplies to meet several types of requirements. Above all, Commonwealth must meet the requirements of its firm customers. In addition, the Company must ensure that its storage facilities have

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36/ See the Siting Council's ORDER in Section III.D.1, infra.

adequate inventory levels prior to the start of the heating season. To the greatest extent possible, Commonwealth also supplies gas to its interruptible customers.

The Company's normal year and design year supply plans indicate that the Company has adequate supplies to meet its forecasted normal and design year requirements throughout the forecast period (Exh. C-1, Table G-22, EFSC Exhs. 20-25).

Accordingly, the Siting Council finds that Commonwealth has established that its base case supply plan is adequate to meet forecasted firm normal year and design year sendout requirements.

4. Design Day Adequacy

Commonwealth must have adequate supply capability to meet the design day requirements of its firm customers. While the total supply capability necessary for meeting normal year and design year requirements is a function of the aggregate volumes of gas available over some contract period, design day supply capability is determined by the maximum daily deliveries of firm pipeline gas and the maximum rate at which supplementals may be dispatched.

a. Previous Conditions

i. Condition Two

In Condition Two of the previous decision, the reliability of Commonwealth's contracts with Boston Gas Company ("Boston Gas") for LNG supplies raised concerns regarding the Company's ability to meet design day sendout requirements in its Cambridge division. Commonwealth Gas Company, 14 DOMSC 213, 246 (1986). The previous decision also raised concerns regarding transportation arrangements with Algonquin to move this LNG. Id., p. 234.

Commonwealth provided a brief history of its arrangements with Boston Gas for LNG supplies (Exh. C-1, Sec. II, pp. 3-5). The Company also indicated that it renegotiated its contract with Boston Gas to provide firm service for Cambridge for the 1986-87 heating season (Exh.

HO-62). Finally, the Company demonstrated that Algonquin filed and received FERC approval for firm transportation of Boston Gas LNG to the Cambridge division during that heating season (id.).

Accordingly, the Siting Council finds that Commonwealth has complied with Condition Two.

ii. Condition Three

In Condition Three of its last decision, the Siting Council ordered Commonwealth to discuss its arrangements with Boston Gas and Algonquin to transfer part of the Framingham division's Algonquin volumes to the Cambridge division under design or near design conditions. Commonwealth Gas Company, 14 DOMSC 213, 246 (1986).

Commonwealth asserted that the availability of capacity on Algonquin's system to transfer volumes from the Framingham division to the Cambridge division depended on the manner in which Boston Gas operated its system (Exh. C-1, Sec. II, pp. 5-7). The Company stated that if Boston Gas took its full entitlement at its Everett take station, then capacity would not be available to displace gas from the Framingham division to the Cambridge division (id.). However, the Company asserted that in the past the capacity has been available whenever Commonwealth has needed it (id.).

Accordingly, the Siting Council finds that Commonwealth has complied with Condition Three.

b. Worcester Division

i. Base Case Analysis

Table 3(a) summarizes Commonwealth's forecasted design day sendout requirements and design day base case supply plan for the Worcester division. In all years, the Company's base case supply plan would meet forecasted design day requirements.

Accordingly, the Siting Council finds that Commonwealth has established that its base case supply plan for the Worcester division is adequate to meet forecasted firm design day sendout requirements in the Worcester division in all years of the forecast period.

ii. Contingency Analysis

The Company indicated that it may retire its Worcester propane facility (see Section III.C.1.c, supra). If all other resources in its base case supply plan remain available to Commonwealth, retirement of the Worcester propane plant would not cause a supply deficiency in the Worcester division in any year of the forecast period (see Table 4).

Accordingly, the Siting Council finds that Commonwealth has established that it has adequate resources to meet its forecasted firm design day sendout requirements in the Worcester division in the event that it retires its Worcester propane plant.

c. Framingham Division

i. Base Case Analysis

Table 3(b) summarizes Commonwealth's forecasted design day sendout requirements and design day base case supply plan for the Framingham division. In all years the Company's base case supply plan would meet forecasted design day requirements.

Accordingly, the Siting Council finds that Commonwealth has established that its base case supply plan is adequate to meet forecasted firm design day sendout requirements in the Framingham division.

ii. Contingency Analysis

Commonwealth plans to increase Hopkinton facility dispatch capability during the forecast period by adding a new transportation arrangement -- the Marathon project -- which affects supply to the Framingham division (see Section III.C.1.a.ii(B), supra).[37] If all

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37/ In the past, the Siting Council has treated projects involving the development and licensing of facilities as supply contingencies. Massachusetts Municipal Wholesale Electric Company, EFSC 85-1, pp. 26-28 (1987); Berkshire Gas Company, EFSC 86-29, p. 27 (1987); Boston Gas Company, EFSC 86-25, p. 67 (1987).

other resources in its base case supply plan remain available to Commonwealth, a one-year delay in the Marathon project would not cause a supply deficiency in the Framingham division (see Table 4).

Accordingly, the Siting Council finds that Commonwealth has established that it has adequate resources to meet its forecasted firm design day sendout requirements in the Framingham division in 1988-89 in the event that the Marathon project is delayed by one year.

d. Cambridge Division

i. Base Case Analysis

Table 3(c) summarizes Commonwealth's forecasted design day sendout requirements and design day base case supply plan for the Cambridge division. The Company's design day base case supply plan indicates inadequate supplies to meet the Company's forecasted design day requirements in the Cambridge division in 1987-88.

Commonwealth identified three base case resource options available to meet the 1987-88 Cambridge supply deficiency (Exh. C-2, pp. 1-7): (1) shifting Algonquin takes from the New Bedford and Framingham divisions to the Cambridge division ("Algonquin transfer"); (2) exchanging gas supplies with Boston Gas ("Boston Gas exchange"); and (3) buying vaporized LNG from Providence Gas Company ("Providence Gas purchase").

(A) Base Case Options

(1) Description

Commonwealth's first option, the Algonquin transfer, shifts Algonquin takes by an estimated 3.0 BBtu/day from the New Bedford division to the Cambridge division, and 1.5-1.85 BBtu/day from the Framingham division to the Cambridge division (Exh. C-2, pp. 2-3). The transfer from both the New Bedford and Framingham divisions involves, at least in part, a forward haul on sections of Algonquin's transmission line where several other Algonquin customers also receive service (Exh.

HO-61). The Company discussed the reliability of this arrangement:

> [T]he Company does not have a firm contractual right to take gas above its MDQ in Cambridge. Algonquin has indicated that they are willing to provide such service as long as doing so does not jeopardize their ability to meet their firm obligations to other customers. Because there would be such a small system-wide reserve margin if the Company chose this method as the only approach to meeting the Cambridge peak day requirements, the Company believes that is [sic] appropriate to develop backup alternatives. (Exh. C-2, p. 3)

The Company's second option, the Boston Gas exchange, involves arrangements between the Company and Boston Gas, Algonquin, and Tennessee (Exh. C-2, pp. 3-5; Tr. III, pp. 10-12). Commonwealth executed a contract with Boston Gas which specifies that "Boston Gas may or may not, at its sole option" release 5.0 BBtu/day from its takes at its Algonquin take station in Everett for transportation by Algonquin to Commonwealth's Cambridge division (Exh. C-2, pp. 3-5, Boston Gas Exchange Contract). The Company's contract with Algonquin provides for "transportation on an interruptible basis" of up to 10.4 BBtu/day (Exh. HO-99). Part of the transportation on the Algonquin system involves a forward haul (Exh. HO-61). The Company planned to replace the Boston Gas volumes by injecting LNG from the Hopkinton facility into Tennessee's mainline for transportation "on an interruptible basis, at Tennessee's sole option" of up to 10.5 BBtu/day to Boston Gas' Tennessee take stations in Reading, Burlington, and/or Arlington (Exh. HO-101; Exh. C-2, pp. 3-5). The transportation on Tennessee's transmission line involves a forward haul for the entire route and includes sections where several other Tennessee customers also receive service (Exh. HO-98).

Another alternative, the Providence Gas purchase, involves contracts with Algonquin and Providence Gas Company ("Providence Gas") (Exh. C-2, pp. 5-7; Tr. III, pp. 12-13). Under the contract with Providence Gas, Commonwealth has the firm rights to request that Providence Gas vaporize up to 5.0 BBtu/day of LNG into its distribution system enabling reduction of its takes at its Algonquin take station in East Providence, Rhode Island (Exh. HO-97; Tr. III, p. 12; Exh. C-2, pp.

5-7). The Company's contract with Algonquin provides for "transportation on an interruptible basis" of up to 10.4 BBtu/day from East Providence to the Cambridge division (Exh. HO-100). Transportation on Algonquin's system involves in part a forward haul along a section where other Algonquin customers also receive service (Exh. HO-61).

(2) Company's Position

The Company maintains that it has in place several complementary options -- the Algonquin transfer, Boston Gas exchange, and Providence Gas purchase -- which assure a continued supply to the Cambridge division through November 1988 or later should the Marathon Project be delayed (Company Brief, p. 18).

In regard to the Algonquin transfer, the Company maintains that this option is the simplest means to meet the deficiency in the Cambridge division, and that Algonquin will allow the transfer as long as it does not jeopardize firm customer obligations (id., pp. 18-19).

In regard to the Boston Gas exchange arrangement, the Company argues that the Tennessee interruptible transportation service will be more reliable than a typical interruptible service because Commonwealth is providing gas to them at a downstream point on their system at a sufficiently high pressure (id., p. 20). The Company also maintains that Tennessee currently has available capacity because the planned NOREX project delivers "significant" volumes of gas downstream of Hopkinton on design days without adding major improvements (id.). The Company further maintains that this option is practical because Commonwealth was able to help other Tennessee customers during the crisis of 1981 by injecting LNG into Tennessee's system (id., p. 21).

Regarding the Providence Gas purchase, the Company maintains that although the transportation is provided on an interruptible basis the service is likely to be "highly" reliable (id.). The Company maintains that the record demonstrates that Algonquin has adequate capacity to provide the service (id.). Finally, the Company also argues that its experience indicates that Algonquin has proven highly dependable in its displacement deliveries to the Cambridge division (id.).

(3) Analysis

The Company has failed to demonstrate that the Algonquin transfer arrangement is sufficiently reliable to be considered firm service because: (1) the Company does not have the firm contractual rights to increase its takes in the Cambridge division; (2) Algonquin will permit the Company to transfer these volumes only if service to Algonquin's firm customers is not jeopardized; and (3) the Algonquin transfer, whether from the New Bedford or Framingham divisions, involves forward haul sections on Algonquin's system where other Algonquin customers also receive service.

The Company also has failed to demonstrate that the Boston Gas exchange is sufficiently reliable to be considered firm service for the following reasons: (1) Commonwealth's contracts with Boston Gas, Algonquin, and Tennessee are interruptible contracts; (2) part of the Algonquin transportation involves a forward haul; and (3) the entire Tennessee transportation involves a forward haul and includes sections where other Tennessee customers also receive service.

Finally, the Company has failed to demonstrate that the Providence Gas purchase is sufficiently reliable to be considered firm for the following reasons: (1) Commonwealth's transportation contract with Algonquin is interruptible; and (2) part of the Algonquin transportation involves a forward haul along sections where other Algonquin customers also receive service.

These factors concerning the Algonquin transfer, Boston Gas exchange, and Providence Gas purchase result in numerous possible situations where service interruption may occur, particularly on the coldest days of the year when many Algonquin and Tennessee customers are most likely to be competing for maximum service. The Company has not shown that sufficient capacity exists in its forward haul service, nor has it shown that it has priority of service in those sections of the forward haul where other customers receive service. In addition, regarding the Algonquin transfer, Algonguin has indicated to the Company that it will provide service only if its firm customers are not jeopardized.

The Siting Council's standard of review for determining design day adequacy explicitly requires that design day supply capability be determined by the maximum daily deliveries of firm pipeline gas as well as the maximum rate at which supplementals may be dispatched. Moreover, the Company's own policy is to meet firm requirements with firm capacity (Tr. I, p. 136). Here, the Company has not met these standards.

Accordingly, the Siting Council finds that Commonwealth cannot reasonably rely for base case planning purposes on the Algonquin transfer, Boston Gas exchange, or Providence Gas purchase to meet firm design day requirements in the Cambridge division.[38]

(B) Cambridge Base Case Adequacy

Based on the record, the Siting Council finds that Commonwealth has failed to establish that its base case supply plan for the Cambridge division is adequate to meet forecasted firm design day sendout requirements in the Cambridge division during the 1987-88 heating season.

ii. Contingency Analysis

Since the Siting Council previously found that the Company's base case supply plan for the Cambridge division is inadequate during the 1987-88 heating season (see Section III.C.4.d.i(B), supra), the Siting Council only evaluates contingencies for the Cambridge division for the period 1988-89 through 1990-91.

Commonwealth plans to increase Hopkinton facility dispatch capability during the forecast period by adding a new transportation

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38/ The Company also argues that at least one of its three non-firm resource options is likely to be available on a design day (Company Brief, p. 22). However, Commonwealth provided no basis for determining whether the three options are more reliable in aggregate than they are individually. Even if these options were shown to be more reliable in aggregate, Commonwealth provided no basis for determining how much more reliable they would be -- particularly whether they are sufficiently reliable collectively to be considered a firm supply for the Cambridge division. Thus, the Siting Council rejects the Company's argument that at least one of the three options is likely to be available to meet design day requirements in the Cambridge division.

arrangement -- the Marathon project -- which affects supply to the Cambridge division (see Section III.C.1.a.ii(B), supra). If all other resources in its base case supply plan remain available to Commonwealth, a one-year delay in the Marathon project would cause a supply deficiency in the Cambridge division of 9.8 percent in 1988-89 (see Table 4).

In the event of a one-year delay in receiving Marathon volumes, Commonwealth identified an action plan for the Cambridge division consisting of three options. However, this action plan comprised the same three options -- extending the Algonquin transfer, Boston Gas exchange, and Providence Gas purchase -- which the Siting Council has previously rejected for base case planning (see Section III.C.4.d.i(A)(3), supra).

Therefore, the Siting Council finds that Commonwealth has failed to establish that it has an action plan to meet its supply deficiency for the Cambridge division in 1988-89 in the event that the Marathon project is delayed by one year. Accordingly, the Siting Council finds that Commonwealth has failed to establish that it has adequate resources to meet its forecasted firm design day sendout requirements in the Cambridge division in 1988-89 in the event that the Marathon project is delayed by one year.

iii. Conclusions on Cambridge Design Day Adequacy

In making its findings regarding Cambridge design day adequacy, the Siting Council must note the failure of Commonwealth's supply planning process. In May 1987, Commonwealth acknowledged that it had insufficient firm supply to meet its firm Cambridge division requirements during the 1987-88 heating season, and therefore that it needed to secure additional supplies (Tr. I, p. 77; see also Tr. II, p. 191). The Company had identified two options for meeting this deficiency (Tr. I, pp. 75-77), but as of November 1987, it had not yet executed any contracts, firm or interruptible, for meeting its Cambridge division supply deficiency (Tr. II, pp. 190-195). Thus, even though Commonwealth had reason to know since the Spring of 1987 that its Cambridge division supply would be deficient to meet forecasted requirements, the Company nonetheless entered the 1987-88 heating season without mitigating this circumstance.

Further, in the event of delay in the Marathon project for one year and the resulting supply deficiency in its Cambridge division during the 1988-89 heating season, Mr. Gowen testified that the Company's action plan "would be to do the same thing that we are planning on doing this year [1987-88] for one more year" (Tr. II, p. 189).[39] However, the record in this proceeding is replete with evidence that this approach is totally untenable. If the Marathon project is delayed beyond the Spring of 1988, Commonwealth again would place its firm Cambridge division customers at an unacceptable level of risk of service interruption.

Commonwealth maintains that the Cambridge division situation will be rectified once the Marathon project is completed. In essence, Commonwealth argues that the Siting Council should overlook the Company's Cambridge division supply deficit since it is of "relatively limited magnitude and short duration" (Company Brief, p. 22). It is startling that a company of Commonwealth's size and resources would ask the Siting Council to condone a situation which directly contravenes its statutory mandate to ensure a necessary energy supply. In future filings, the Siting Council expects Commonwealth to file supply plans which address adequacy with its due importance and consideration in all forecast years.

e. New Bedford Division

i. Base Case Analysis

Table 3(d) summarizes Commonwealth's forecasted design day sendout requirements and design day base case supply plan for the New Bedford division. In all years, the Company's base case supply plan would meet forecasted design day requirements.

39/ Mr. Gowen estimated that Algonquin would need FERC approval of the Marathon project by "late March or early April" of 1988 in order to provide the Marathon service during the 1988-89 heating season (Tr. II, pp. 205-206).

Accordingly, the Siting Council finds that Commonwealth has established that its base case supply plan for the New Bedford division is adequate to meet forecasted firm design day sendout requirements in the New Bedford division in all years of the forecast period.

ii. Contingency Analysis

Commonwealth plans to increase Hopkinton facility dispatch capability during the forecast period by adding a new transportation arrangement -- the Marathon project -- which affects supply to the New Bedford division (see Section III.C.1.a.ii(B), supra). If all other resources in its base case supply plan remain available to Commonwealth, a one-year delay in the Marathon project would not cause a supply deficiency in the New Bedford division (see Table 4).

Accordingly, the Siting Council finds that Commonwealth has established that it has adequate resources to meet its forecasted firm design day sendout requirements in the New Bedford division in 1988-89 in the event that the Marathon project is delayed by one year.

f. Conclusions on Design Day Adequacy

The Siting Council has found that Commonwealth (1) complied with Conditions Two and Three, (2) established that its supply plan in the Worcester division is adequate to meet forecasted firm design day sendout requirements in the Worcester division in the base case and under a reasonable range of contingencies, (3) established that its supply plan for the Framingham division is adequate to meet forecasted firm design day sendout requirements in the Framingham division in the base case and under a reasonable range of contingencies, (4) failed to establish that its supply plan for the Cambridge division is adequate to meet forecasted firm design day sendout requirements in the Cambridge division in the base case, (5) failed to establish that its supply plan and action plan for the Cambridge division is adequate to meet forecasted firm design day sendout requirements in the Cambridge division under a reasonable range of contingencies, and (6) established that its supply plan for the New Bedford division is adequate to meet forecasted firm design day sendout requirements in the New Bedford division in the base case and under a reasonable range of contingencies.

5. Cold Snap Adequacy

In Condition Six of its last decision, the Siting Council ordered Commonwealth to provide an analysis of its cold snap preparedness or an explanation of why such an analysis is unnecessary. Commonwealth Gas Company, 14 DOMSC 213, 244 (1986). The Siting Council has defined a cold snap as a prolonged series of days at or near design conditions. Id. A company must demonstrate that the aggregate resources available to it are adequate to meet the near maximum level of sendout over a sustained period of time, and that it has and can sustain the ability to deliver such resources to its customers. Boston Gas Company, EFSC 86-25, p. 65 (1987).

In explaining its view as to why such an analysis is unnecessary, Commonwealth asserted that it "does not rely upon replenishment of any of its storage or supplemental inventories during the course of a design winter .... If we can meet requirements for an entire design winter, we can meet requirements for any part of one" (Exh. C-1, Sec. II, p. 9). The Company asserted that its Hopkinton and Acushnet LNG storage capacities, Tennessee firm transportation of Consolidated underground storage gas, and Algonquin firm transportation underground storage gas permit it to dispatch gas to meet cold snap requirements without having to replace supplemental gas supplies, manage inventory turnover, or plan replacement supplies (Exh. HO-23).

For the most recent period of sustained design-day or near design-day conditions (the Winter of 1980-81), Commonwealth stated that it "made surplus supplies available to other gas distribution companies in the New England area" and that its "supply situation is even stronger now that it was in 1981, as a result of the changes in [its] supply mix" (id.)

Based upon the foregoing, the Siting Council finds that the Company has established that an analysis of the Company's cold snap preparedness is unnecessary as part of this supply plan. Accordingly, the Siting Council finds that Commonwealth has complied with that portion of

Condition Six pertaining to cold snap analyses.[40]

6. Conclusions on the Adequacy of Supply

The Siting Council has found that Commonwealth (1) established that it has an identified set of resources to meet its forecasted firm normal year and design year sendout requirements, (2) established that it has an identified set of resources to meet its forecasted firm design day sendout requirements in its Worcester, Framingham, and New Bedford divisions in the base case and under a reasonable range of contingencies, (3) failed to establish that it has an identified set of resources to meet its forecasted firm design day sendout requirements in the base case, or a supply plan and action plan to meet sendout requirements under a reasonable range of contingencies in the Cambridge division, and (4) established that cold snap analyses are unnecessary as part of this supply plan. Accordingly, in light of the findings regarding the Cambridge division, the Siting Council finds that the Company has failed to establish that it has adequate resources to meet its design day sendout requirements for the forecast period.

D. Least-Cost Supply

1. Comparison of Alternatives on an Equal Footing

In 1986, the Massachusetts legislature amended the Siting Council's statute to require the Siting Council to approve a company's long-range forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J. To ensure that a company's supply plan minimizes cost, the Siting Council also evaluates whether the company's supply planning process adequately considers

40/ Commmonwealth is not required to file a cold snap analysis as part of its next forecast filing.

alternative resource additions, including demand-side options, on an equal basis. Berkshire Gas Company, EFSC 86-29, p. 33 (1987); Fall River Gas Company, 15 DOMSC 97, 115 (1986).

Commonwealth has implemented several pilot conservation programs (see Section III.C.2, supra). Although the Company has evaluated the cost effectiveness of certain conservation programs, it has not incorporated any programs as part of its supply planning process because decreases in demand thus far have been relatively small. Regarding load management, the Company's only such program is its interruptible rate. Thus, Commonwealth has not provided any thorough analysis of how it compares the costs and benefits of Company-sponsored conservation and load management programs with the costs and benefits of obtaining new supplies.

Accordingly, the Siting Council finds that the Company has failed to establish that its supply planning process treats C&LM on an equal footing with other resource options. The Siting Council ORDERS the Company in its next forecast filing to implement a supply planning methodology which treats conservation and load management on an equal footing with other resource options such that supply costs are minimized subject to supply adequacy considerations.

2. Supply Cost Analysis

The Siting Council recently articulated its concerns regarding the need for gas companies to engage in least-cost planning. In its Order in Docket No. 85-64, the Siting Council found that it was appropriate to focus on that portion of its mandate that requires the Siting Council to ensure an energy supply for the Commonwealth "at the lowest possible cost." G.L. c. 164, sec. 69H. In so doing, the Siting Council must evaluate whether a company assesses the relative costs of the various resource options it could use to meet its needs, since options with similar reliability may have different costs and vice versa, and since different load additions with varying gas usage patterns impose different kinds of supply obligations in terms of cost.

In its most recent decision regarding Commonwealth, the Company was ordered to comply with the Siting Council's Decision in Docket No.

85-64 and its implementation in Administrative Bulletin 86-1. Specifically, to enable the Siting Council to ensure that the Company's supply plan minimizes cost, the Company was ordered, as part of Condition Six, to perform an internal study comparing the costs of a reasonable range of practical supply alternatives in the event that the Company's filing indicated the addition of a long-term firm gas supply contract. Commonwealth Gas Company, 14 DOMSC 213, 245 (1986).

In the instant case, Commonwealth's decision to add firm transportation services associated with the Tennessee backhaul and Marathon projects triggered the need for the Company to perform such studies.[41] In particular, cost studies were required in order to evaluate whether these new projects were least-cost additions to the Company's existing supply plan, taking adequacy and reliability concerns into account.

a. Tennessee Backhaul

Prior to entering into the Tennessee backhaul agreements, Commonwealth compared it to Tennessee's AVL/NOREX project and distribution system modifications which would allow Commonwealth to increase Hopkinton facility dispatch into Worcester (Exh. C-2, p. 10; Exh. HO-38; Tr. I, pp. 124-131). To receive 30.0 BBtu/day through the

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41/ The Company maintains that it has not proposed to add any long-term gas supply contracts and that there are no new gas supplies connected with the Marathon project (Company Brief, p. 25). However, in its last decision regarding Commonwealth, the Siting Council clearly stated that the requirement to perform an internal cost study is intended to cover instances when contractual arrangements are proposed for the firm transportation of storage gas. Commonwealth Gas Company, 14 DOMSC 213, 245 (1986).

Although the Tennessee backhaul agreements specify interruptible transportation of storage gas (see Section III.C.1.a.ii(A)(1), supra), the Company asserts that the Tennessee backhaul is essentially a firm service (Company Brief, p. 23). The Siting Council accepted this assertion in Section III.C.1.a.ii(A)(2), supra. The Marathon agreement explicitly states that service is for firm transportation of storage gas (see Section III.C.1.a.ii(B), supra). Thus, the requirement to perform an internal cost study clearly applies to both the Tennessee backhaul and Marathon services.

Tennessee backhaul, the Company stated that the one-time demand charges totalled $157,000 while variable charges are $0.0444 per MMBtu transported (Exh. C-2, p. 10; Exhs. HO-38, HO-60, HO-79). For the AVL/NOREX project, Commonwealth estimated that demand charges would have been about $1.2 million per year for 7.142 BBtu/day and $4.9 million per year for 30.0 BBtu/day (Exh. C-2, p. 10; Exh. HO-38). Commonwealth estimated that the modifications to its distribution system necessary to allow it to move an additional 30.0 BBtu/day into Worcester would have cost more than $5 million (id.).

The Company also analyzed different Tennessee backhaul volumes. Mr. Gowen explained that Tennessee had indicated an ability to deliver an additional 30.0 BBtu/day down the Worcester lateral at a cost negligibly higher than the cost to deliver an additional 7.0 BBtu/day (Tr. I, pp. 73-74).

The Siting Council finds that the Company has compared the costs of the Tennessee backhaul to the costs of a reasonable range of practical alternatives. Accordingly, the Siting Council finds that Commonwealth has demonstrated that the Tennessee backhaul contributes to ensuring a least-cost supply plan.

Therefore, the Siting Council finds that Commonwealth has complied with that portion of Condition Six pertaining to cost studies for the Tennessee backhaul arrangement.

b. Marathon Project

Commonwealth considered various options prior to entering into the Marathon agreement, including increasing Algonquin underground storage, contracting for Boston Gas LNG supplies, and arranging for Algonquin displacement service (Tr. I, pp. 132-38). However, Mr. Gowen estimated additional Algonquin underground storage to be at least four times more expensive than Marathon (id., pp. 134-135). He also provided that, while the Company had used Boston Gas LNG for the previous three years, the LNG came from "their Distrigas account" and therefore is not a sufficiently reliable long-term supply option (id., p. 135). In addition, he asserted that Algonquin's displacement service was a best efforts arrangement and therefore not reliable enough for long-term firm capacity (id., pp. 135-136).

Commonwealth compared the construction costs of eight alternative configurations of Marathon delivery points and volumes and chose the one that "minimized the overall cost of the project" (Tr. I, p. 170; Exh. HO-71). Construction costs for the alternative configurations ranged from $9.7 million (for the selected configuration) to $18.6 million (Exh. HO-71).

Mr. Gowen cited additional benefits of the Marathon project. First, Marathon provides access to Algonquin spot market suppliers in addition to the existing Tennessee suppliers for replenishing storage volumes at the Hopkinton facility (Tr. I, 137-138). In addition, Marathon provides the ability to transfer gas directly between the Algonquin and Tennessee systems allowing Commonwealth to take further advantage of price differences between its two pipeline suppliers (id.).

The Siting Council finds that the Company has compared the costs of the Marathon project to the costs of a reasonable range of practical alternatives. Accordingly, the Siting Council finds that Commonwealth has demonstrated that the Marathon project contributes to ensuring a least-cost supply plan.

Therefore, the Siting Council finds that Commonwealth has complied with that portion of Condition Six pertaining to cost studies for the Marathon project.

3. Conclusions on Least-Cost Supply

The Siting Council has found that Commonwealth failed to establish that its supply planning process treats C&LM on an equal footing with other resource options. The Siting Council also has found that Commonwealth has demonstrated that the two projects planned for addition during the forecast period -- the Tennessee backhaul and Marathon project -- contribute to ensuring a least-cost supply plan.

Although the Siting Council has found that the Company has failed to establish that its supply planning process treats C&LM on an equal footing with other resource options, on balance the Siting Council finds that the Company has established that its supply plan ensures a least-cost energy supply.

E. Summary

The Siting Council has found that the Company has failed to establish that it has adequate resources to meet its design day sendout requirements for the forecast period. The Siting Council also has found that the Company has established that its supply plan ensures a least-cost energy supply.

Accordingly, the Siting Council hereby REJECTS Commonwealth's supply plan.

IV. DECISION AND ORDER

The Siting Council hereby REJECTS the sendout forecast and supply plan of Commonwealth Gas Company as presented in the Fourth Supplement to the Second Long-Range Forecast of Gas Requirements and Resources.

The Siting Council hereby APPROVES Hopkinton LNG, Inc.'s Fourth Supplement to the Second Long-Range Forecast.

The Siting Council ORDERS Commonwealth in its next forecast filing:

1. to provide (a) an analysis of potential sendout forecasting improvements that may result from the use of EDD, (b) an analysis of the costs that would be incurred if the Company were to collect EDD, and (c) an analysis of the feasibility of using an external EDD source while internal EDD data are collected;

2. to develop a systematic methodology for updating its range of weather data;

3. (a) to provide a complete analysis of the availability and reliability of New Bedford-specific weather data, and (b) to justify any continued use of Worcester weather data for forecasting sendout requirements in the New Bedford division;

4. to provide (a) a copy of the consultant's feasibility study and recommendations regarding an appropriate forecasting methodology for Commonwealth, and (b) an indication of whether, and if so how, the Company intends to implement all such recommendations;

5. to provide a complete analysis of the effects on the Worcester lateral of any potential third party transportation or supply;

6. to provide a complete analysis of design day flow and pressure in Tennessee's mainline considering the effects of the Tennessee backhaul, Granite State Gas Transmission Company's Portland Pipeline project, and Distrigas of Massachusetts Corporation's

LNG imports in addition to any future projects expected to materialize within the five-year forecast period;

7. to implement a supply planning methodology which treats conservation and load management on an equal footing with other resource options such that supply costs are minimized subject to supply adequacy considerations;

The Siting Council FURTHER ORDERS Commonwealth and Hopkinton LNG to file their next forecast on October 1, 1988.

Frank P. Pozniak

Frank P. Pozniak
Hearing Officer

UNAIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of April 7, 1988, by the members and designees present and voting: Joseph Miglio (for Chairperson Sharon M. Pollard, Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Michael Brown (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Stephen Umans (Public Electricity Member). Absent: Dennis J. LaCroix (Public Gas Member); Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard
Chairperson

April 7, 1988
Date

TABLE 1

Commonwealth Gas Company
Split-Year Sendout Forecast by Customer Class
(BBtu)

	1987-88		1990-91	
	Normal	Design	Normal	Design
Worcester				
Residential Heating	6,642	7,286	6,875	7,533
Residential General	84	84	72	72
Commercial	3,639	3,962	4,177	4,538
Industrial	3,376	3,493	3,868	4,014
Worcester Total*	14,242	15,326	15,527	16,692
Framingham				
Residential Heating	4,913	5,271	5,087	5,469
Residential General	132	132	115	115
Commercial	2,560	2,736	2,927	3,135
Industrial	1,592	1,617	1,657	1,687
Framingham Total*	9,450	10,009	10,052	10,672
Cambridge				
Residential Heating	3,748	4,084	3,801	4,140
Residential General	160	160	149	149
Commercial	2,272	2,441	2,818	3,032
Industrial	243	260	263	283
Cambridge Total*	6,614	7,136	7,237	7,810
New Bedford				
Residential Heating	4,020	4,368	4,161	4,519
Residential General	191	191	170	170
Commercial	1,702	1,828	1,936	2,084
Industrial	818	835	884	906
New Bedford Total*	6,920	7,411	7,350	7,878
COMPANY TOTAL	37,226	39,882	40,166	43,052

* Includes Company-use and unaccounted-for gas

Sources: Exh. C-1, Tables G-1 thorugh G-5; Exh. HO-20

TABLE 2

Commonwealth Gas Company and Hopkinton LNG, Inc.
Summary of Pipeline Supply and Transportation Contracts,
Storage Services, and Peakshaving Facilities

Contract		Type	AVL/ACQ (BBtu/Yr)	MDQ (BBtu/Day)	Contract Expiration Date
Algonquin	F-1	Supply	19,165	71.0	11/01/89
	F-2	Supply	3,739	10.4	10/31/92
	F-3	Supply	1,107	3.1	10/31/92
	F-4	Supply	5,818	16.0	10/31/89
	WS-1	Supply	2,137	35.6	4/15/00
	STB-1	Sto/Trans	600	6.2	4/15/00
	SS-III	Sto/Trans	434	4.3	3/31/06
Tennessee	CD-6	Supply	16,858	55.4	11/01/00
	FSST-NE	Trans	926	8.3	3/31/95
	Backhaul	Trans	---	30.0	3/89[a]
Consolidated GSS		Storage	926	8.4	4/01/00
Acushnet LNG			500	30.0	1/97[b]
Hopkinton LNG			3,500	240.0	1/97[b]
Propane			31	14.4	

a. The 436 contract expires in 3/89; the 7(c) contract expires on December 24, 1988. However, the Company assumes that the Tennessee backhaul service will be available throughout the forecast period.

b. Commonwealth's contract with Hopkinton LNG expires in 1/97.

<u>Sources</u>: Exh. C-1, Tables G-14 and G-24; Exh. HO-37.

TABLE 3(a)

Commonwealth Gas Company
Base Case Design Day Supply Plan

Worcester Division
(BBtu)

	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:[a]	123.4	126.7	130.3	133.3
RESOURCES:				
Tennessee CD-6	55.8	55.8	55.8	55.8
Tennessee FSST-NE	8.3	8.3	8.3	8.3
Algonquin F-1	0	0	0	0
Algonquin F-2	0	0	0	0
Algonquin F-3	0	0	0	0
Algonquin F-4	0	0	0	0
Algonquin WS-1	0	0	0	0
Algonquin ST-B	0	0	0	0
LNG Hopkinton[b]	82.8	82.8	82.8	82.8
LNG Acushnet	0	0	0	0
Firm Propane	14.4	14.4	14.4	14.4
TOTAL RESOURCES:	161.3	161.3	161.3	161.3
SURPLUS (DEFICIT):	37.9	34.6	31.0	28.0
RESERVE:	30.7%	27.3%	23.8%	21.0%

Notes:

a. Firm requirements are based on the Company's 1986 forecast filing. The Siting Council found in Section II.D, that the Company's design day forecasting methodology is not appropriate and the resulting forecast of Worcester design day requirments is not reliable.

b. LNG Hopkinton includes 30.0 BBtu/day for Tennessee backhaul service.

c. This Table assumes that 1 BBtu = 1 MMCF.

Sources: Exhs. C-1, C-2, HO-37, HO-91

TABLE 3(b)

Commonwealth Gas Company
Base Case Design Day Supply Plan

Framingham Division
(BBtu)

	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:[a]	81.6	84.9	86.4	88.6
RESOURCES:				
Tennessee CD-6	0	0	0	0
Tennessee FSST-NE	0	0	0	0
Algonquin F-1	24.9	24.9	24.9	24.9
Algonquin F-2	0	0	0	0
Algonquin F-3	0	0	0	0
Algonquin F-4	2.5	2.5	2.5	2.5
Algonquin WS-1	15.8	15.8	15.8	15.8
Algonquin ST-B	0	0	0	0
LNG Hopkinton[b]	46.8	67.8	67.8	67.8
LNG Acushnet	0	0	0	0
Firm Propane	0	0	0	0
TOTAL RESOURCES:	90.0	111.0	111.0	111.0
SURPLUS (DEFICIT):	8.4	26.1	24.6	22.4
RESERVE:	10.3%	30.7%	28.5%	25.3%

Notes:

a. Firm requirements are based on the Company's 1986 forecast filing. The Siting Council found in Section II.D, that the Company's design day forecasting methodology is not appropriate and the resulting forecast of Framingham design day requirments is not reliable.

b. LNG Hopkinton includes 21.0 BBtu/day for Marathon service beginning in 1988-89.

c. This Table assumes that 1 BBtu = 1 MMCF.

Sources: Exhs. C-1, C-2, HO-37, HO-61, HO-91

TABLE 3(c)

Commonwealth Gas Company
Base Case Design Day Supply Plan

Cambridge Division
(BBtu)

	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:[a]	59.9	65.4	67.2	69.5
RESOURCES:				
Tennessee CD-6	0	0	0	0
Tennessee FSST-NE	0	0	0	0
Algonquin F-1	25.4	25.4	25.4	25.4
Algonquin F-2	10.1	10.1	10.1	10.1
Algonquin F-3	3.0	3.0	3.0	3.0
Algonquin F-4	4.8	4.8	4.8	4.8
Algonquin WS-1	9.6	9.6	9.6	9.6
Algonquin ST-B	6.1	6.1	6.1	6.1
LNG Hopkinton[b]	0	14.0	14.0	14.0
LNG Acushnet	0	0	0	0
Firm Propane	0	0	0	0
TOTAL RESOURCES:	59.0	73.0	73.0	73.0
SURPLUS (DEFICIT):	(0.9)	7.6	5.8	3.5
RESERVE:	(1.5%)	11.6%	8.6%	5.0%

Notes:

a. Firm requirements are based on the Company's 1986 forecast filing. The Siting Council found in Section II.D, that the Company's design day forecasting methodology is not appropriate and the resulting forecast of Cambridge design day requirments is not reliable.

b. LNG Hopkinton includes 14.0 BBtu/day for Marathon service beginning in 1988-89.

c. This Table assumes that 1 BBtu = 1 MMCF.

Sources: Exhs. C-1, C-2, HO-37, HO-61, HO-91

TABLE 3(d)

Commonwealth Gas Company
Base Case Design Day Supply Plan

New Bedford Division
(BBtu)

	1987-88	1988-89	1989-90	1990-91
FIRM REQUIREMENTS:[a]	61.9	64.0	65.1	66.5
RESOURCES:				
Tennessee CD-6	0	0	0	0
Tennessee FSST-NE	0	0	0	0
Algonquin F-1	19.4	19.4	19.4	19.4
Algonquin F-2	0	0	0	0
Algonquin F-3	0	0	0	0
Algonquin F-4	7.4	7.4	7.4	7.4
Algonquin WS-1	9.6	9.6	9.6	9.6
Algonquin ST-B	0	0	0	0
LNG Hopkinton[b]	0	5.0	5.0	5.0
LNG Acushnet	30.0	30.0	30.0	30.0
Firm Propane	0	0	0	0
TOTAL RESOURCES:	66.4	71.4	71.4	71.4
SURPLUS (DEFICIT):	4.5	7.4	6.3	4.9
RESERVE:	7.3%	11.6%	9.7%	7.4%

Notes:

a. Firm requirements are based on the Company's 1986 forecast filing. The Siting Council found in Section II.D, that the Company's design day forecasting methodology is not appropriate and the resulting forecast of New Bedford design day requirments is not reliable.

b. LNG Hopkinton includes 5.0 BBtu/day for Marathon service beginning in 1988-89.

c. This Table assumes that 1 BBtu = 1 MMCF.

Sources: Exhs. C-1, C-2, HO-37, HO-61, HO-91

TABLE 4

Commonwealth Gas Company
Design Day Contingency Analysis
(BBtu)

1. Retirement of Worcester Propane Plant

Division	Year	Base Case Surplus (Deficit)	Propane Facility Contingency	Contingency Surplus (Deficit)	Reserve
Worcester	1988-89	34.6	(14.4)	20.2	15.9%
	1989-90	31.0	(14.4)	16.6	12.7%
	1990-91	28.0	(14.4)	13.6	10.2%

2. Delay of Marathon Project by One Year

Division	Year	Base Case Surplus (Deficit)	Marathon Contingency	Contingency Surplus (Deficit)	Reserve
Framingham	1988-89	26.1	(21.0)	5.1	6.0%
Cambridge	1988-89	7.6	(14.0)	(6.4)	(9.8%)
New Bedford	1988-89	7.4	(5.0)	2.4	3.7%

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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 (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Gas Company and Massachusetts LNG, Inc. for Approval of an Occasional Supplement to their Third Long-Range Forecast of Gas Requirements and Resources	EFSC 86-25A

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:

Brian G. Hoefler

TABLE OF CONTENTS

The Energy Facilities Siting Council hereby APPROVES, subject to CONDITIONS, the petition of Boston Gas Company and Massachusetts LNG, Inc. to construct in Hingham, Massachusetts (1) a pipeline of approximately 7,640 feet in length with a maximum allowable operating pressure of 200 pounds per square inch gauge along the route described herein, and (2) a regulator station in Hingham Circle.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Boston Gas Company ("Boston Gas" or "the Company") distributes and sells natural gas to residential, commercial, and industrial customers in the City of Boston and 73 other eastern and central Massachusetts communities including the Towns of Braintree, Weymouth, Hingham, Hull, Cohasset, Abington, Rockland, and Whitman ("South District"). Boston Gas is the largest gas distribution company in the Commonwealth with about 500,000 customers and firm sendout of about 64,000 thousand dekatherms ("MDth")[1] during the 1985-86 split year.

All of the Company's capital stock is held by Eastern Gas and Fuel Associates. Algonquin Gas Transmission Company ("Algonquin") is Boston Gas' largest pipeline supplier. Tennessee Gas Pipeline Company ("Tennessee"), a division of Tenneco, Inc., also delivers supplies to Boston Gas. The Company's one subsidiary, Massachusetts LNG, Inc. ("Mass. LNG"), holds long-term leases on two liquefied natural gas ("LNG") storage facilities.[2]

1/ One MDth equals one billion Btus ("BBtu") or roughly one million cubic feet ("MMCF") of natural gas. For purposes of this review, the Energy Facilities Siting Council assumes that one MDth is equivalent to one MMCF.

2/ Since Mass. LNG makes no wholesale or retail sales of gas, the pipeline and regulator station proposed in the occasional supplement, and the Energy Facilities Siting Council's review of that proposal, are exclusive to Boston Gas.

In its review of the Company's most recent forecast filing, the Energy Facilities Siting Council ("Siting Council" or "EFSC") rejected the Company's sendout forecast and supply plan. Boston Gas Company, 16 DOMSC 173 (1987).

Boston Gas proposes to construct approximately 1.5 miles of welded steel pipeline with a maximum allowable operating pressure ("MAOP") of 200 pounds per square inch gauge ("psig") (Exh. HO-1; Exh. BGC-3). The proposed pipeline would operate at about 137.5 psig and extend the Company's existing "feeder system" in the South District (id.). The Company also has proposed to provide a new supply source to its existing 60 psig distribution system in the South District by constructing a 137.5-to-60 psig regulator station at the terminus of the proposed pipeline (id.). Boston Gas estimated the capital cost of the proposed facilities to be $1.36 million (Exh. BGC-3, pp. 2, 4).[3]

B. Procedural History

On March 6, 1987, the Company filed an Occasional Supplement to its 1986 forecast and supply plan, requesting approval to construct approximately 1.5 miles of 200 psig pipeline and a 137.5-to-60 psig regulator station in the Town of Hingham (Exh. HO-1).

On April 23, 1987, the Siting Council conducted a public hearing in the Town of Hingham. In accordance with the directions of the Hearing Officer, Boston Gas provided notice of the public hearing and adjudication.

On May 8, 1987, the Company filed an amendment to its Occasional Supplement, setting forth a modification of its proposed pipeline route and a redesign of its proposed regulator station (Exh. HO-2).

Petitions to intervene were filed by the Hingham Historical

3/ Boston Gas presented three options for a portion of the pipeline route (see Section III.B.2, infra). The range of cost estimates for the proposed facilities under these three options is $1.36 to $1.40 million (Exh. BGC-3, pp. 2, 4).

Commission ("HHC"), Robert Grant ("Grant"), and Robert Siegel ("Siegel"). On May 8, 1987, the Company filed its response in opposition to all petitions to intervene. On May 15, 1987, the Hearing Officer issued a Procedural Order granting the petitions to intervene of HHC, Grant, and Siegel.

On June 1, 1987, the Hearing Officer conducted a pre-hearing conference (1) to consider the Company's arguments regarding certain information requests of the Siting Council Staff, and (2) to establish a procedural schedule for the remainder of the proceeding.

The Siting Council conducted evidentiary hearings on July 14, July 15, July 24, and July 31, 1987. Boston Gas presented four witnesses: John J. Gilfeather, planning and design engineer; John J. McCarthy, distribution superintendent; Gregory Tomlinson, director of marketing and business analysis; and Leo Silvestrini, manager of rates and economic analysis. HHC presented two witnesses: John P. Richardson, a former member of HHC; and Peter L. Puciloski, a member of the Town of Hingham Planning Board. In addition, Siegel presented a statement on his own behalf.

Pursuant to a briefing schedule established by the Hearing Officer, HHC filed its brief on August 14, 1987. On August 17, 1987, the Company filed its initial brief. On August 24, 1987, the Company filed a reply brief.

On October 23, 1987, the Company filed an second amendment to its Occasional Supplement. In this amendment, the Company (1) stated that it planned to construct approximately 2,780 feet of its proposed line prior to the 1987-88 winter, and (2) proposed three options which constituted its proposed route (Exh. BGC-3).

The Siting Council conducted two additional evidentiary hearings on November 17 and November 20, 1987 to consider the Company's amendment of October 23, 1987. At these hearings, the Company presented two witnesses, Leo Silvestrini, and Charles P. Buckley, vice president of distribution and engineering.

The Hearing Officer entered 52 exhibits in the record, largely composed of responses to information and record requests.[4] Boston Gas offered seven exhibits into the record.[5] HHC entered 31 exhibits into the record while Siegel entered four exhibits.

C. Jurisdiction

The Company's Occasional Supplement is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, requiring gas companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by any other state agency.

The Company's proposal to construct a 1.5-mile pipeline operating at a pressure of 137.5 psig and a 137.5-to-60 psig regulator station falls squarely within the fifth definition of "facility" set forth in G.L. c. 164, sec. 69G:

> (5) any new pipeline for the transmission of gas having a normal operating pressure in excess of one hundred pounds per square inch guage which is greater than one mile in length except restructuring, rebuilding, or relaying of existing transmission lines of the same capacity.

At the same time, the Company's decision to construct (1) 2,780 feet of the proposed pipeline at a pressure of 90 psig, and (2) the proposed regulator station (Exhs. BGC-3, BGC-4), does not fall within

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4/ In addition, a document included in Exhibit EFSC-61 from the record of Boston Gas Company, 16 DOMSC 173 (1987), was incorporated by reference in this proceeding. For purposes of this decision, the Siting Council will refer to that document as Exhibit HO-53.

5/ Boston Gas requested that certain documents (Exhs. BGC-1, BGC-2, HO-7, HO-8, HO-9, HO-17, HO-18, and HO-47) receive protective treatment. Pursuant to 980 CMR 4.05(2)(d), all intervenors elected not to review such documents. Accordingly, the Hearing Officer granted the Company's request.

the Siting Council's definition of "facility." Accordingly, the Company's construction of the non-jurisdictional portion of its proposal does not violate G.L. c. 164, sec. 69I. However, the Company's amended proposal to construct the entire 1.5-mile pipeline for operation at a pressure of 137.5 psig still requires Siting Council approval. Therefore, for purposes of this review, the Siting Council considers the Company's proposal as amended.[6]

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present plans that address the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section II.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply (see Section III, infra).

6/ The Siting Council notes, however, that any expansion of a jurisdictional facility within the five-year forecast period would require Siitng Council approval, even if said expansion is less than one mile in length. G.L. c. 164, sec. 69I.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposed energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources[7] to meet reliability or economic efficiency objectives. The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated 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 Council 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. Northeast Energy Associates, 16 DOMSC 335, 344-360 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); Bay State Gas Company, 6 DOMSC 102, 110-111 (1981); Boston Gas Company, 4 DOMSC 50, 80 (1980); Boston Edison Company, 2 DOMSC 58, 62 (1977); New England Electric

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7/ In this discussion, "additional energy resources" is used generically to encompass both energy and capacity additions including, but not limited to, gas transmission lines, synthetic natural gas facilities, liquefied natural gas facilities, propane facilities, gas storage facilities, energy or capacity associated with gas sales agreements, and energy or capacity associated with conservation and load management.

System, 2 DOMSC 1, 9 (1977); Eastern Utilities Associates, 1 DOMSC 312, 313 (1977). With regard to contingencies, the Siting Council 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. Nantucket Electric Company, 15 DOMSC 363, 380-383 (1987); Massachusetts Electric Company, 13 DOMSC 119, 137 (1985); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Eastern Utilities Associates, 10 DOMSC 71, 76-78 (1983); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Boston Gas Company, 8 DOMSC 1, 8-9 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Middleboro Gas and Electric Department, 4 DOMSC 220, 229-236 (1980); Boston Edison Company, 3 DOMSC 153, 156-162 (1980); Boston Edison Company, 2 DOMSC 58, 60-62 (1977); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977); Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 101 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985); Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

2. Description of the Existing System

Boston Gas supplies the South District with natural gas from Algonquin's Birchcroft Road gate station and with propane-air from the Company's Braintree propane plant ("Braintree plant") (Exh. HO-11). Customers in the South District are supplied by a 60 psig, intermediate pressure distribution system fed by a 137.5 psig high pressure "feeder" system which, in turn, is fed from the Birchcroft Road take station (Exh. HO-1, p. 4; Exh. HO-3). The Braintree plant supplies propane-air directly to the 60 psig system (Tr. III, p. 15).

Three regulator stations -- one each located at the intersection of Fort Hill and West Streets ("Fort Hill regulator station"), at the intersection of Lincoln and Beal Streets ("Lincoln regulator station"), and at the Braintree plant ("Braintree regulator station") -- currently supply the 60 psig system from the 137.5 psig system (Exh. HO-3). Boston Gas identified the Fort Hill and Lincoln regulator stations as the primary existing sources that supply the Towns of Hingham and Hull (Exh. HO-1, p. 4).

3. Reliability

The Company asserted that the existing 60 psig system serving the Hingham and Hull area "has reached its capacity and must be reinforced" since, "Without the increase in capacity, the Company will be unable to meet the additional requested level of service in this area" (Exh. HO-1, pp. 4-5; see also Tr. II, p. 12).

a. Expected Load Growth[8]

As a preliminary matter, the Siting Council notes that the record of this proceeding contains several inconsistencies regarding the growth markets which would be served by the proposed project. Boston Gas stated in its initial filing that it had studied ways "to serve the proposed increased load in Hingham and Hull" (Exh. HO-1, p. 6). The Company also indicated in its initial filing that the proposed project would result in a new feed to the distribution system "serving Hingham, Hull and Cohasset customers" which would "allow Boston Gas to meet new requests for service in the area served by this system" (id., p. 7). Subsequently, however, Company witnesses stated that justification for the pipeline is based on load growth in Hull only (Tr. II, pp. 121-123, 137, 167-170; Tr. V, pp. 7-49). Boston Gas provided that it had identified "specific projects" in Hull that the proposed line is

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8/ The Siting Council discusses load growth based on the total hourly load of connected end-use equipment ("connected load"), but discusses distribution system capacity based on coincident load under design hour weather conditions ("design hour load"). During this proceeding, the Company assumed that load growth would contribute to design hour load at a rate of 70 percent of connected load (Tr. V, pp. 43-46; Exh. HO-5).

intended to serve (Tr. II, pp. 128, 142, 144; Tr. V, pp. 15-17).[9] Boston Gas also provided that about one-half of its proposed investment "is required to improve deliverability to existing customers in the Hull area" and the remaining half would provide additional capacity to serve new customers in Hull (Exh. HO-37).[10] Finally, Mr. Silvestrini, the Company's witness, testified regarding "the urgent need for the proposed pipeline to serve projected load growth in the Hingham-Hull-Cohasset area" (Exh. BGC-6, p. 2).

While Company has asserted that Hull is the project's intended market, and that a project surcharge policy applies only to new Hull customers, the weight of the evidence indicates that growth markets in Hingham and, to a lesser extent, Cohasset, also would be served by the proposed project (see also Section II.A.3.b, infra). Therefore, the Siting Council considers expected load growth in all three towns in its evaluation of the proposed project.

Boston Gas identified expected load growth in Hull, Hingham, and Cohasset for the five years, 1987-1991 (Exh. BGC-7; Tr. VII, pp. 8-10).[11] This expected load growth is summarized in Table 1.

9/ The Company's witness, Mr. Gilfeather, identified the specific projects in Hull as the Horizon Condominiums, Seascape Condominiums, Sunset Condominiums, and Damon School adding that these "four major projects" total 105 thousand cubic feet per hour ("MCFH") of design hour load (Tr. II, p. 127; Tr. V, p. 16).

10/ On October 2, 1986, the Company implemented its "Hull Surcharge Policy" whereby Boston Gas is collecting hook-up fees from new customers in Hull until the Company recovers about $610,000 of the cost of the proposed pipeline and regulator station (Exhs. HO-37, HO-39; Tr. V, pp. 21-24, 42-43). Mr. Silvestrini testified that the Company plans to terminate Hull surcharges once it has added 150 MCFH of connected load in Hull (Tr. V, pp. 43-46). Based on a more recent analysis, the Company increased its estimated allocation of project costs to Hull customers to $685,000 (Exh. HO-52), but did not indicate whether or how the increased estimate would affect the surcharge policy.

11/ Boston Gas provided several analyses of expected load growth during the course of this proceeding (see Exhs. HO-5, HO-37, HO-39, HO-52; Exh. HHC-1; Exh. BGC-7). However, at the final hearing in this proceeding, Mr. Silvestrini testified that the load projections in Exh. BGC-7 updated earlier studies (Exh. BGC-6, p. 2; Tr. VII, p. 8). Thus, in its review of the proposed project and facilities, the Siting Council considers the Company's load growth projections presented in Exh. BGC-7.

b. Effects of Load Growth on Existing System

Boston Gas designs its distribution system to meet design hour load on a 65 degree day ("DD") day (Exhs. HO-4, HO-5). The Company estimated the 1986-87 design hour load for the South District to be approximately 1,733 MCFH (Exh. HO-5).

The Company used network analysis techniques to study its South District distribution system and determine that the existing system could not support the expected load growth (Exh. HO-1, pp. 5-7; Exh. HO-14; Tr. III, p. 22). In order to ensure adequate service to South District customers, the Company believes it must provide at least 4-5 psig at the system low point (Exh. HO-53). Mr. Gilfeather testified that the existing distribution system in the South District is adequate given existing load levels (Tr. III, pp. 10, 12). However, a network analysis study of the existing system "indicated that the pressure at a number of points in the distribution system would be zero (0) if the requested loads were added without the reinforcement" (Exh. HO-14; see also Exh. HO-7 and Tr. III, p. 22).

To substantiate this claim, Boston Gas provided a network analysis study of the existing system with the original design hour load growth of 105 MCFH identified in Hull and 32 MCFH approved by the Company in Hingham (Exh. HO-7). This study indicated that the distribution system would not be able to provide the minimum required pressure of 4-5 psig to all customers if such load growth was added (id.).

Based on updates of expected load growth, the Company estimated the additional load in Hull, Hingham, and Cohasset that could be connected through 1991 without the proposed project (Exh. BGC-7; Tr. VII, pp. 8-10). Boston Gas concluded that its distribution system capacity is insufficient to allow the Company to meet expected load growth in Hull beginning in 1987 and in Hingham beginning in 1988, but sufficient to allow the Company to meet expected load growth in Cohasset in all years except 1987 (see Table 1) (id.).

Accordingly, the Siting Council finds that Boston Gas has demonstrated that its existing distribution system in the South District is inadequate to satisfy expected load growth with acceptable reliability in Hull, Hingham, and Cohasset through 1991.

4. Conclusion on Need

Boston Gas has demonstrated that its existing distribution system in the South District is inadequate to satisfy expected load growth with acceptable reliability in Hull, Hingham, and Cohasset through 1991. Accordingly, the Siting Council finds that Boston Gas has established that additional energy resources are needed in the South District.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H requires the Siting Council 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 lowest possible cost. In addition, G.L. c. 164, sec. 69I requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[12]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Northeast Energy Associates, 16 DOMSC 335, 360-380 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 212-218 (1986); Massachusetts Electric Company, 13 DOMSC 119, 141-183 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985); Boston Gas Company, 11 DOMSC 159, 161-168 (1984).

12/ G.L. c. 164, sec. 69I also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the Company's proposed site, as well as other site locations, in Section III, infra.

2. Need

The proposed project consists of (1) a new 137.5-to-60 psig regulator station providing an additional feed to the Company's 60 psig distribution system in the South District, and (2) a new 137.5 psig pipeline supplying the new regulator station.

Table 1 summarizes the Company's analysis of the amount of expected load growth in Hull, Hingham, and Cohasset that could be added with the proposed project (Exh. BGC-7; Tr. VII, pp. 8-10). The Company's analysis indicated that (1) for Hull the proposed project could support expected load growth during 1987, 1988, and most of 1989, but could not support all of the expected load growth in 1989 or any of the expected load in 1990 and 1991, (2) for Hingham the proposed project could support expected load growth during most of 1988, but could not support all of the expected load growth in 1988 or any of the expected load growth in 1989, 1990, and 1991, and (3) for Cohasset the proposed project could support the expected load growth during 1987 (id.).

Boston Gas discussed three alternative approaches for ameliorating the effects on the distribution system of increased load -- conservation and load management ("C&LM"), load growth curtailment in the Hull area, and construction of a satellite peakshaving plant in Hingham (Exhs. HO-1, p. 17, HO-20, HO-21).

With respect to C&LM, Boston Gas stated that it "would certainly consider conservation or load management to be a new source of supply once it had been quantified and identified as reliable" (Exh. HO-20). However, the Company added that its residential conservation database indicates a trend toward increased normalized consumption (id.). That trend along with the level of anticipated load growth in relation to existing sales in this "limited geographic area," led the Company to conclude that "it is not feasible to consider conservation and load management as alternatives to construction" of the proposed facilities (id.).

Although the Company asserted that load growth curtailment in the Hull area would have certain disadvantages, the Company raised no arguments that such curtailment would be unable to mitigate the deficiency in distribution system capacity that would occur if the

Company realized expected load growth through 1991 (id.).

Boston Gas stated that project objectives also could be met with a liquefied natural gas ("LNG") or propane satellite peakshaving plant in Hingham (Exh. HO-1, p. 17, HO-21). However, the Company asserted that, although technically feasible, a satellite peakshaving plant could not be placed in service within the required time frame (id.). To support its assertion, the Company estimated the time required to complete site analysis and acquisition (6-12 months), to procure material and equipment (6-9 months), and to construct the plant (3-6 months), but was unable to estimate the time required to license it (Exh. HHC-8). While the Company has failed to provide even such rudimentary analysis as a critical path of the steps necessary to place a satellite peakshaving plant in service, the record contains no evidence indicating that such a plant could address the previously identified need in a timely manner.

The Siting Council finds that the Company has demonstrated that C&LM and a satellite peakshaving facility fail to address the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Council compares the proposal only to the alternative approach of curtailing load growth in the Hull area.

3. Cost

Boston Gas asserted that curtailing load growth "would not be in the best interest of the Company's existing customers" since marginal revenue from expected load growth additions would be greater than the marginal cost of serving the growth (Exh. HO-20; see also Tr. V, pp. 7-11). The Company explained that this difference benefits existing customers in the near-term by deferring the need for a rate increase and in the long-term by decreasing rates at the time of the next request for a rate increase (Exh. HO-20; Tr. V, pp. 7-11). The Company concluded that existing customers' rates would be higher without the expected load growth (id.).

In support of its position, the Company provided the "Projected Cash Flow" of the proposed project and a simulated "Test-Year Ratecase Report" (Exh. HO-52; see also Exhs. HO-37, HO-39). Based on these analyses, the Company estimated that the net present value of the impact on all customer rates of the proposed project would be a reduction of about $696,000 assuming a discount rate of 14 percent, and that the internal rate of return achieved by the Company would be about 54 percent (Exh. HO-52).

Accordingly, the Siting Council finds that the proposed project is superior to the alternative approach of curtailing load growth in the Hull area with respect to cost.

4. Environmental Impacts

The only environmental impacts of the proposed project identified by Boston Gas were construction impacts relating to land features and uses, water resources, air quality, and noise (Exh. HO-1, pp. 24-26). However, the Company indicated that it would take any necessary measures to mitigate all such impacts (id.).[13]

Boston Gas identified no environmental impacts relating to curtailment of load growth in the Hull area.

Based on the record, the Siting Council finds that the alternative approach of curtailing load growth in the Hull area is superior to the proposed project with respect to environmental impacts.

5. Conclusion: Weighing Need, Cost, and Environmental Impacts

The Siting Council has previously found that (1) the proposed project is superior to the alternative approach of curtailing load growth in the Hull area with respect to cost, and (2) curtailing load growth in the Hull area is superior to the proposed project with respect to environmental impacts.

In a previous decision, the Siting Council noted that curtailing load growth may be an acceptable option in the event of emergencies or sudden supply shortages, but is undesirable as a result of inadequate

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13/ The Siting Council discusses measures identified in this proceeding in Section III.E, infra.

supply planning. Boston Gas Company, 16 DOMSC 173, 243 (1987). If a company's analysis and forecasts show that new load growth has benefits to customers and to the company, then that company should ensure that it provides the resources to accommodate such growth. Id. In the instant proceeding, Boston Gas has demonstrated that new load growth has economic efficiency benefits to customers as well as the Company. At the same time, the Company has demonstrated that the environmental impacts of the proposed project, while more extensive than curtailing load growth, are acceptable. See Section III.E.4, infra.

Accordingly, the Siting Council finds that Boston Gas has demonstrated that its proposed project is consistent with ensuring a necessary energy supply with minimum impact on the environment at lowest possible cost.

In making this finding, the Siting Council acknowledges that, while the proposed project would have satisfied the demands of the specific projects initially set forth by Boston Gas, the Company's proposed project cannot satisfy all of the need identified in Section II.A, supra (see Table 1). The Company's premise for this sort of planning is that the incremental load beyond that met by the proposed project could be added with minimal distribution system expansion and cost (Tr. VII, pp. 14-15).

The Siting Council's enabling statute requires gas companies to present comprehensive plans for a five-year period. G.L. c. 164, sec. 69I. If uncertainty surrounds future need within this period, then gas companies must implement flexible planning processes which allow adaptation to reasonably likely planning scenarios. In this case, such a flexible planning process might include a proposed project sufficient to meet all identified need, but capable of being placed in service in phases or increments. Since Boston Gas has chosen to propose a project which does not meet all identified need within the five-year time frame, any expansion of these jurisdictional facilities by 1991 to meet South District load growth require Siting Council review.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, sec. 69I requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternative approaches in terms of cost, environmental impacts, and meeting identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical siting alternatives, and (2) that the proposed site for the facility is preferable to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 195-196, 229-237 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986); Massachusetts Electric Company, 13 DOMSC 119, 183-184, 190-248 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 76-81 (1985).

B. Description of the Proposed Facilities and Alternatives

1. Regulator Station Sites

The regulator station site chosen by Boston Gas is an island in the middle of a traffic circle at the intersection of Route 3A, Summer Street, and Green Street ("Hingham Circle") (Exh. HO-1, pp. 8-9).

Two alternative regulator station sites were identified during the proceeding. The first alternative site is associated with the pipeline route alternative crossing Hingham Bay (id., p. 22).

This regulator station would provide a new source to the South District 60 psig system in the vicinity of Nantasket Avenue and Edgewater Road ("Nantasket Avenue site") (id.). The second alternative site would be located in the vicinity of Rockland Street and Summer Street about 2,500 feet east of the proposed regulator station location ("Rockland Street site") and would be associated with the proposed route and all alternative routes except for the Hingham Bay alternative (Exh. HO-22).

2. Pipeline Routes

a. Background

To provide service to the proposed regulator station in Hingham Circle, Boston Gas identified a route for the proposed pipeline as well as four alternative routes (Exh. HO-1).[14] However, during the course of this proceeding, the Company "decided that it was appropriate ... to undertake necessary distribution system reinforcement" prior to the 1987-88 heating season (Exh. BGC-3, p. 2). Therefore, Boston Gas proceeded with construction of approximately 3,360 feet of 12-inch pipeline from a point near the intersection of Central and South Streets to the proposed regulator station site in Hingham Circle (Exh. BGC-5, p. 2; Exh. BGC-3, p. 2).

In light of this construction, the Company presented three options for completing the remainder of the proposed facilities (Exh. BGC-5, p. 3; Exh. BGC-3, pp. 3-4). Still, the Company requested approval for facilities from the intersection of Beal and North Streets to Hingham Circle (Exh. BGC-3, p. 5), and maintained that the five original route alternatives would remain facilities alternatives in addition to the three proposed route options (Tr. VI, pp. 31-32).

14/ The fifth alternative route would cross Hingham Bay and supply a new regulator station at the Nantasket Avenue site (Exh. HO-1, p. 22).

b. Proposed Route: North Street Options

Boston Gas proposes to construct about 7,640-7,820 feet of 12-inch, 200 psig welded steel main beginning at the intersection of Beal and North Streets and running in a generally easterly direction to Hingham Circle (Exh. BGC-3; Exhs. HO-35, HO-45).

The first option for North Street ("Proposed Option 1") would consist of about 7,680 feet of pipeline and would proceed east from the intersection of Beal and North Streets to Marsh's Bridge where the pipeline would cross the Massachusetts Bay Transportation Authority ("MBTA") railroad right of way ("ROW") to South Street, then run in South Street to the intersection with Central Street (Exh. BGC-3; Exh. HO-35). The route would continue in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3).

The second option for North Street ("Proposed Option 2") would consist of about 7,640 feet of pipeline and would proceed east from the intersection of Beal and North Streets to Hersey Street where the pipeline would cross the railroad ROW to South Street, then run in South Street to the intersection with Central Street (Exh. BGC-3; Exhs. HO-35, HO-45). The remainder of the route would continue identically to Proposed Option 1 in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3).

The third option for North Street ("Proposed Option 3") would consist of about 7,820 feet of pipeline and would proceed east from the intersection of Beal and North Streets to Central Street where the pipeline would cross the railroad ROW to the intersection of Central and South Streets (Exh. BGC-3; Exhs. HO-35, HO-45). The remainder of the route would continue identically to Proposed Option 1 in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3).

c. Alternative A: South Street

The "South Street alternative" would involve construction of about 7,360 feet of 12-inch, 200 psig steel main beginning at the intersection of West and South Streets and running in a generally easterly direction in South Street to the intersection with Central Street (Exhs. HO-1, HO-51). The remainder of the route would continue identically to Proposed Option 1 in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3; Exh. HO-51).

d. Alternative B: Route 3A

The "Route 3A alternative" would involve construction of about 14,500 feet of 12-inch, 200 psig steel main beginning at the intersection of Route 3A and Beal Street and running in Route 3A generally in easterly and southeasterly directions to the proposed regulator station site in Hingham Circle (Exhs. HO-1, HO-51).

e. Alternative C: Lincoln Street

The "Lincoln Street alternative" would involve construction of about 14,760 feet of 12-inch, 200 psig steel main beginning at the intersection of Route 3A and Beal Street and running generally in an easterly direction in Route 3A, Bulow Road, Lincoln Street, and Central Street to the intersection with South Street (Exhs. HO-1, HO-51). The remainder of the route would continue identically to Proposed Option 1 in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3; Exh. HO-51).

f. Alternative D: Fottler Road

The "Fottler Road alternative" would involve construction of about 12,960 feet of 12-inch, 200 psig steel main beginning at the intersection of Fottler Road and Beal Street and running generally in an easterly direction in Fottler Road, Bulow Road, Lincoln Street, and Central Street to the intersection with South Street (Exhs. HO-1, HO-51). The remainder of the route would continue identically to Proposed Option 1 in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed regulator station site in Hingham Circle (Exh. BGC-3; Exh. HO-51).

g. Alternative E: Hingham Bay

The "Hingham Bay alternative" would involve construction of about 24,000 feet of 12-inch, 200 psig steel main beginning at the intersection of Route 3A and Beal Street and running generally in a northeasterly direction over an embankment into the Weymouth Back River, down the Weymouth Back River, across Hingham Bay, and back to land at Sunset Point in Hull (Exh. HO-1). The route would continue in a generally easterly direction in Fairmont Road and Edgewater Road to the Nantasket Avenue regulator station site (Exhs. HO-1, HO-51).

h. Railroad Right of Way

An alternative route was identified during this proceeding which the Company did not evaluate initially. This alternative would follow, in part, the inactive MBTA railroad ROW[15] where it runs between North and South Streets in generally an easterly direction from the intersection of West and South Streets to Central Street (Exh. HHC-27; Tr. III, p. 67; Tr. IV, p. 31). At Central Street the alternative would turn south in Central Street to the intersection with South Street, then continue identically to Proposed Option 1 for the remainder of the route in a generally easterly direction in South Street, North Street, Station Street, Mill Street, Water Street, and Summer Street to the proposed

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15/ This railway has been inactive since 1977 (Tr. IV, pp. 32, 63-64).

regulator station site in Hingham Circle (Exh. BGC-3; Exh. HO-1). The "railroad ROW alternative" would involve about 7,600 feet of 12-inch, 200 psig main (Exh. HHC-9).

Mr. Richardson, HHC's witness, suggested a modified route between West and Central Streets. This route would begin at the intersection of West and South Streets running in generally an easterly direction in South Street to Marsh's Bridge, joining the railroad ROW at Marsh's Bridge, and continuing along the railroad ROW from Marsh's Bridge to Central Street (Tr. III, p. 93; Tr. V, pp. 74-76, 82).

C. Site Selection Process

1. Regulator Station Sites

Boston Gas stated that, in analyzing alternatives to meet the proposed increase in load, it considered constructing a new regulator station "at various points" (Exh. HO-1, p. 6). The Company asserted that its selection of Hingham Circle as the proposed regulator station location was based on minimization of traffic flow impacts, network analysis results, and the presence of a 60 psig distribution main (Exh. HO-22; Tr. III, pp. 29-30). Although the Company developed a set of criteria to identify possible sites for its proposed regulator station, the record indicates that these criteria were developed and applied haphazardly in the Company's site selection process.

For instance, the Company did not provide traffic impact analyses of either the proposed or alternative regulator station sites. Thus, there is no way to evaluate whether the Company's assertion regarding traffic impacts is relevant.

In regard to network analysis results, the Siting Council notes that Boston Gas provided results for the case without any new facilities and for certain cases with the proposed regulator station in Hingham Circle (Exhs. HO-7, HO-8, HO-17; Exh. BGC-2). However, the Company did not provide results for the alternative regulator station sites. Thus, no conclusions about alternative regulator station sites may be drawn from network analysis results. Still, Mr. Gilfeather testified that the Rockland Street site would provide higher pressure than the Hingham

Circle site (Tr. III, p. 30), thereby providing the ability to serve more load. However, he added that any advantages of the Rockland Street site were outweighed by the additional cost of about $400,000 to lay the extra 2,500 feet of main, especially since the proposed site would adequately service the proposed load level (Tr. III, pp. 30-31; Exh. HO-22). Still, in the absence of quantified supporting analysis Mr. Gilfeather's testimony may be discounted, particularly when a subsequent market analysis indicated that the proposal could not support all of the identified load growth in Hull and Hingham (see Section II.B.2, supra).

Regarding the presence of a 60 psig distribution main, almost the entire South District is served by the 60 psig system (Exh. HO-9; Tr. III, p. 19). Thus, even with the additional constraint of siting a regulator station close to Hull and Cohasset (Exh. HO-1, p. 7), a wide range of sites on a 60 psig main are evident, including the Hingham Circle, Rockland Street, and Nantasket Avenue sites (Exh. HO-9). The Company provided no further criteria for screening its 60 psig distribution system for potential regulator station sites.

Boston Gas has provided scant evidence of a site selection process capable of identifying and screening appropriate regulator station sites. The Company itself conceded that the only location evaluated for siting a regulator station was at Hingham Circle (Exh. HO-21). Although Boston Gas has not demonstrated that it developed and applied a reasonable set of criteria for identifying possible sites for its proposed regulator station, the Siting Council makes no findings here regarding the Company's consideration of a reasonable range of practical alternatives for siting the proposed regulator station.

2. Pipeline Routes

Boston Gas used a pipeline route screening process that first identified several alternative routes then applied selection criteria to determine the best route. The Company's analysis did not explicitly compare the economic costs and environmental impacts of the proposed facilities and alternatives in order to screen out impractical routes. Nevertheless, for purposes of this review, the Siting Council eliminates those alternatives which clearly are not practical.

In its screening process, the Company stated that its criteria consisted of (1) minimizing construction costs,[16] (2) avoiding wetlands, and (3) avoiding newly resurfaced streets (Exh. HO-1, pp. 9, 17).

The pipeline lengths and construction cost estimates associated with the proposed and alternative pipeline routes are summarized in Table 2. The only construction cost estimate that is clearly unacceptable is that associated with the Hingham Bay alternative, estimated to be more than $10 million (760 percent) more expensive than Proposed Option 2 (see Table 2). Thus, the Siting Council finds that the Hingham Bay alternative is not a practical alternative. The remainder of the alternatives require further review of both economic costs and environmental impacts.

The Company initially asserted that the Route 3A alternative would infringe upon two wetlands (Exh. HO-1, p. 19; Tr. II, pp. 93-94). However, the Company later indicated that this alternative would most likely be built in the roadway thereby avoiding construction in the wetlands (Tr. II, pp. 56-59; Tr. III, pp. 88-90). Since any wetlands impacts would be insignificant, they do not provide a basis for screening out alternatives.[17]

Three alternatives would require trenching in streets resurfaced or reconstructed during 1986: the entire 14,500-foot length of the Route 3A alternative (Exh. HO-1, p. 19; Tr. II, p. 59); about 4,300 feet of the Lincoln Street alternative (Exh. HO-1, pp. 20-21; Tr. II, pp. 84-85); and approximately 700 feet of the Fottler Road alternative (Exh.

16/ The Company presented minimizing pipeline length and avoiding railroad ROW crossings as two separate criteria (Exh. HO-1, pp. 9, 17). For purposes of this analysis, the Siting Council groups these criteria under the heading "minimizing construction costs."

17/ The Hingham Bay alternative would require traversing the Weymouth Back River and crossing Hingham Bay -- about 18,000 feet of construction in wetlands or waterways (Exh. HO-1, pp. 22-23, Exhibit G). Although the Siting Council already has found this alternative impractical based on cost, such an extensive disturbance of wetlands and waterways could be grounds for eliminating an alternative if other practical alternatives exist.

HO-1, p. 22; Tr. II, p. 85). Disturbing recently resurfaced streets along with the cost differences between these three alternatives and Proposed Options 1, 2, and 3, and the South Street alternative (see Table 2) could be sufficient grounds for finding the Route 3A, Lincoln Street, and Fottler Road alternatives impractical. However, the Route 3A alternative is the only route among the proposed options and remaining alternatives that does not pass through a historically sensitive area of Hingham (Exhs. HHC-15, HHC-17, HHC-18, HHC-20, HHC-22, HHC-23, HHC-24, HHC-26, HHC-27, HHC-28, HHC-29, HHC-31; Exh. S-4; Exhs. HO-1, HO-51; Exh. BGC-3; Tr. III, pp. 65-66, 97-99; Tr. V, p. 95).[18] Therefore, in weighing economic costs and environmental impacts, the Siting Council finds that the Lincoln Street and Fottler Road alternatives are not practical alternatives, but that the Route 3A alternative requires further review.

Although none of the parties provided a systematic analysis of the railroad ROW alternative based on the Company's screening criteria, several aspects of the railroad ROW alternative raise questions about its practicality. First, while HHC's witnesses asserted that the railroad ROW alternative (1) would cause "the least potentially adverse environmental impact" (Exh. HHC-16), and (2) would be the most advantageous route by moving construction away from structures and protecting archeological attributes (Tr. V, pp. 74-75), HHC failed to present sufficient evidence to demonstrate that the railroad ROW alternative is environmentally practical. In fact, the presence of a swamp and the necessity of several Town Brook crossings prompted Mr. Richardson to suggest the relocation of a pipeline section from the railroad ROW out into South Street from West Street to Marsh's Bridge (Tr. III, p. 93).[19]

18/ The Siting Council considers the implications of pipeline construction in a historic district in Section III.E, infra.

19/ The Town Brook follows the railroad ROW alternative and crosses it on several occasions (Exh. HO-43; Exhs. HHC-23, HHC-24, HHC-26; Tr. II, p. 66; Tr. III, pp. 84-88). However, the intervenors provided no environmental analysis of the effects of pipeline construction on Town Brook.

Further, Boston Gas presented evidence that there is considerable uncertainty about the future of this railway -- specifically, whether the MBTA will reactivate the railway (Tr. II, pp. 69, 72, 86-93; Tr. IV, pp. 43-45, 64-67). Although HHC's witness, Mr. Puciloski, conceded that the MBTA may have plans to reactivate the ROW, he asserted that any such plans "are on the back burner" until certain environmental and logistical concerns are addressed (Tr. IV, pp. 43-45, 64-67). However, Mr. Gilfeather stated that, based on discussions with MBTA representatives responsible for future development of this ROW, the Company's position was that any pipeline laid within the railroad ROW faced "significant risk" of having to be relocated or replaced (Tr. II, pp. 91-92). Hence, the Siting Council agrees that the risk of relocating or replacing a pipeline constructed in the railroad ROW discourages such a route.

Accordingly, the Siting Council finds that the railroad ROW alternative is not a practical alternative.

The Siting Council considers the remainder of the options and alternatives -- Proposed Options 1, 2, and 3, South Street, and Route 3A -- in Sections III.D, III.E, and III.F, infra.

Based on the foregoing, the Siting Council finds that Boston Gas has developed and applied a reasonable set of criteria for identifying possible routes for its proposed pipeline. Accordingly, the Siting Council finds that Boston Gas has considered a reasonable range of practical alternatives for siting the proposed pipeline.

D. Cost Analysis of the Proposed Facilities and Alternatives

Total estimated construction costs, including regulator station construction, for Proposed Options 1, 2, and 3, the South Street alternative, and the Route 3A alternative are summarized in Table 2. Table 2 indicates that the estimated costs to construct Proposed Options 1, 2, and 3, and the South Street alternative fall within a range of about $70,000 or five percent. This five-percent range is well within the Company's contingency margin included in each cost estimate of about ten percent (Exh. HO-1, Exhibits A - G; Exh. HO-27). In addition, the Company's witness, Mr. Buckley, testified that cost differences between

Proposed Options 1, 2, and 3 are minimal, and therefore any of the proposed options is acceptable to the Company (Exh. BGC-5, p. 4). Another Company witness, Mr. Silvestrini, added that the South Street alternative has "virtually the same cost" as Proposed Options 1, 2, and 3 (Tr. VII, p. 8). The Route 3A alternative, however, would be at least $1.17 million (82 percent) more expensive to construct than Proposed Options 1, 2, and 3, and the South Street alternative (see Table 2).

Accordingly, the Siting Council finds that, on the basis of cost, Proposed Options 1, 2, and 3, and the South Street alternative are comparable, but are preferable to the Route 3A alternative.

E. Environmental Analysis of the Proposed Facilities and Alternatives

The only environmental impacts identified during the course of this proceeding were related to Hingham's historic areas, trees, and street conditions. The Siting Council reviews these impacts in its analysis of the proposed facilities and alternatives.

1. Historic District

a. Background on Historic District

A section of Hingham where the Company proposes to construct its pipeline has historical significance: In 1966, the Massachusetts Legislature, by special act, designated the area around the intersection of Lincoln and North Streets as the "Lincoln Historic District" (Tr. III, pp. 65-66; Exh. HHC-27). The Lincoln Historic District also contains one building designated as a National Historic Landmark (Exh. HHC-18). In addition, the Hingham Board of Selectman appointed a committee to review the historic nature of the area along North Street and South Street from West Street to Hingham Harbor (Tr. III, pp. 66-67; Exhs. HHC-21, HHC-27). Mr. Richardson, a member of that committee, testified that the committee plans to place the issue of designation as a Local Historic District ("Proposed Local Historic District") before the Town of Hingham who may, by two-thirds vote, make such a designation

(Tr. III, pp. 66-67, 99; Tr. V, p. 95; Exhs. HHC-22, HHC-27).

b. Effects of Construction on Historic District

All three of the Company's proposed pipeline route options as well as the South Street alternative would traverse the Proposed Local Historic District (Exh. BGC-3; Exh. HHC-27). In addition, Proposed Option 3 would run through the Lincoln Historic District (id.).[20] The Route 3A alternative would not enter any areas with identified historic significance (Exhs. HO-1, HO-51; Exh. HHC-27), and no party asserted that the Route 3A alternative would affect historic structures in any way.

The historic nature of the North Street/South Street area raised concerns about the effects on historic structures of vibration and dust from the pipeline construction process (Exhs. HHC-15, HHC-19; Exh. S-4; Tr. III, pp. 77-82; Tr. IV, pp. 28-30, 55-60, 77-78; Tr. V, pp. 140, 145-146).

The record is clear that significant vibrations would have detrimental effects on historic structures, and that many of the structures within the Proposed Local Historic District lie only 10 to 15 feet from the edge of the road (id.). However, the Company asserted that its construction process would not transmit vibrations to any

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20/ Pursuant to EFSC regulation 980 CMR 7.07(7)(d)(2), a proponent of a gas pipeline facility must identify land uses along the proposed pipeline corridor including areas designated for protection as historic districts.

The Company's original proposed pipeline route would have been constructed through the Lincoln Historic District (Exh. HO-1; Exh. HHC-27; Tr. III, pp. 65-66). However, the Company failed to identify the Lincoln Historic District in its petition and was unable to provide such information on request (Exhs. HO-1, HO-34; Tr. II, p. 50). In addition, Mr. Gilfeather testified that, in selecting the North Street route, the Company had not considered North Street's historical nature since it only had come to the Company's attention through the Siting Council's proceeding (Tr. II, pp. 19, 52). Finally, the Company's witnesses stated that they had not contacted the Massachusetts Historical Commission about any aspects of the Company's proposal (Tr. II, p. 49).

structures, particularly if trenching operations maintain at least eight feet of clearance from the structures (Exh. HO-30; Exh. HHC-14; Tr. II, pp. 34-36, 38, 78-79; Tr. V, pp. 121-123).

The Company's witness, Mr. McCarthy, stated that he has been responsible for two other major Boston Gas pipeline construction projects within the past 18 years (Tr. II, pp. 78-79). He testified that those projects included construction through residential neighborhoods without damage to homes, and that the Company's proposed pipeline would have even less of an impact on adjacent structures (id., pp. 78-79). The Hingham Historical Commission's witnesses stated that they could not dispute Mr. McCarthy's assertion that the Company's construction techniques would not affect adjacent structures (Tr. III, pp. 111-112; Tr. IV, pp. 56-57).

However, Mr. Puciloski, a member of the Hingham Planning Board and also a homeowner along the proposed pipeline route, noted that the Planning Board's by-laws require new developments to place utilities, including gas pipelines, at least 27 feet away from buildings (Tr. IV, pp. 6, 78-81, 85; Exh. HHC-16). He added that maintaining at least 27 feet between the pipeline and structures during construction would alleviate his concerns about vibrations affecting their structural integrity (Tr. IV, p. 81).

HHC has raised legitimate concerns about pipeline construction through historically sensitive areas. Boston Gas indicated that it could take several measures to assure abutters that its proposed facilities would have no effect on adjacent structures. First, the Company agreed to relocate its pipeline in certain areas away from existing structures maintaining at least eight feet between the edge of its trench and adjacent structures (Exhs. HO-35, HO-41, HO-45; Tr. II, p. 13; Tr. V, 120-123, 135). In addition, the Company stated that it would use saw-cut techniques rather than jackhammers to open streets thereby reducing one source of vibrations (Tr. II, p. 13). Mr. Richardson agreed that use of saw-cut techniques would be preferable to jackhammers (Tr. V, pp. 60-61). Finally, the Company indicated that it would be willing to install equipment during the construction process to monitor vibrations near structures (Exh. HO-30; Tr. II, p. 40).

While HHC has shown that significant vibrations could harm the structural integrity of historic structures, the Siting Council finds that HHC has failed to establish that vibrations from the Company's proposed construction process would have detrimental effects on adjacent historic structures.

Regarding the effects of dust on historical structures, HHC observed that these structures typically house "sensitive furnishings" such as antique wallpapers, murals, paintings, fabrics, and fine polished surfaces (Exh. HHC-19). HHC asserted that these sensitive furnishings can be "severely damaged and diminished in value by excessive dust" (id.). The Company indicated that if necessary it would use dust control measures such as application of calcium chloride (Exhs. HO-1, pp. 25-26, HO-31).

While the Company did not refute HHC's assertion, HHC has provided no evidence that the dust expected to be raised by the Company's construction process would be in any way excessive.[21] Therefore, the Siting Council finds that HHC has failed to establish that dust from the Company's proposed construction process would be significant enough to have detrimental effects on adjacent historic structures.

Although HHC has failed to establish that either vibrations or dust from the Company's proposed construction process would have detrimental effects on historic structures, the Siting Council finds that pipeline construction through Hingham's historic areas warrants special construction considerations, including those presented by Boston Gas.

Accordingly, the Siting Council finds that the proposed construction process would have an acceptable impact upon adjacent structures in Hingham's Lincoln Historic District and Proposed Local Historic District. Since Proposed Option 3 would involve construction through the Lincoln Historic District, the Siting Council finds that Proposed Option 3 is less preferable than Proposed Options 1 and 2, the

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21/ Siegel, a homeowner along the route of the proposed options, testifed that dust causes certain health concerns for his wife (Tr. V, pp. 141-145).

South Street alternative, and the Route 3A alternative. The Siting Council further finds that, on the basis of effects of the construction process on historic structures, Proposed Options 1 and 2, and the South Street alternative are comparable, but are slightly less preferable than the Route 3A alternative.

2. Tree Impacts

HHC and Siegel raised concerns about the impact of construction on trees, some of which have historical significance, along the proposed route (Tr. III, pp. 80-81; Tr. V, pp. 146-148). The Company stated that it does not intend to remove or damage any existing trees during pipeline construction (Exhs. HO-1, p. 14, HO-33). The Company indicated that it had consulted with Hingham officials about potential tree impacts and precautions necessary to maintain trees (Exh. HO-33; Tr. II, pp. 44-47). Mr. McCarthy stated that the Company agreed to realign its pipeline around a tree in one instance, and that field conditions may require further precautions such as further realignment or perhaps tunneling under tree roots (Tr. II, pp. 44-47; Exh. HO-33).

Accordingly, the Siting Council finds that with the proposed mitigation measures the proposed facilities would have an acceptable impact on trees. The Siting Council further finds that, on the basis of effects of the construction process on trees, Proposed Options 1, 2, and 3, the South Street alternative, and the Route 3A alternative are comparable.

3. Street Conditions

When planning to construct a pipeline in streets, the condition of those streets is a primary consideration. Boston Gas observed that, for the Route 3A alternative, the entire 14,500 feet of pipeline construction would take place in sections of Route 3A that had been either resurfaced or reconstructed during 1986 (Exh. HO-1, p. 19; Tr. II, pp. 59-60, 101-103). The Company asserted that, although the Massachusetts Department of Public Works might issue a permit to construct a pipeline in Route 3A, the conditions attached to that permit probably would require extensive street restoration (Tr. II, pp. 59-60, 101-103). Thus, while pipeline construction in Route 3A may be possible, its recent resurfacing and reconstruction discourages digging a new pipeline trench. No party asserted that Proposed Options 1, 2, and 3 or the South Street alternative would require construction in streets recently resurfaced or restored.

However, Siegel raised concerns about the length of time necessary to restore streets to their initial condition after construction is complete (Tr. V, pp. 148-149). He cited other recent utility construction in Hingham which caused a "horrible situation" upon completion due to the unreasonable length of time for street restoration (Tr. V, pp. 148-149).[22]

As part of its proposed construction activities, Boston Gas stated that "all surfaces will be restored to their original condition as soon as possible" (Exh. HO-1, p. 10; see also Exh. HO-1, p. 14). The Company revised its plan to include street restoration "as soon as practicable" after construction (Exh. S-3). Mr. Buckley noted that, in order to allow for trench backfill to settle, the Company normally installs an asphalt "binder" as a temporary restoration measure then returns at a later date to complete final restoration (Tr. VI, pp. 17-19). Still, the Company has not provided a schedule for restoring pavement.

Based on the foregoing, the Siting Council finds that, if the Company provides and adheres to a schedule for completing street restoration, construction of the proposed facilities would have an acceptable impact on street conditions. The Siting Council further finds that, on the basis of initial street condition, Proposed Options 1, 2, and 3, and the South Street alternative are comparable, but are preferable to the Route 3A alternative.

4. Conclusion

The Siting Council finds that, with the construction process

22/ Boston Gas was not a party to the utility construction cited by Siegel (Exh. S-3; Tr. V, pp. 148-149).

proposed by Boston Gas, the proposed facilities will have an acceptable impact on all of the environmental concerns addressed in this proceeding, whether construction is along Proposed Options 1, 2, and 3, the South Street alternative, or the Route 3A alternative.

The Siting Council has found that, with the construction process proposed by Boston Gas, (1) Proposed Option 3 is less preferable than Proposed Options 1 and 2, the South Street alternative, and the Route 3A alternative on the basis of effects of the construction process on historic structures, (2) Proposed Options 1 and 2, and the South Street alternative are comparable, but are slightly less preferable than the Route 3A alternative, on the basis of effects of the construction process on historic structures, (3) Proposed Options 1, 2, and 3, the South Street alternative, and the Route 3A alternative are comparable on the basis of effects of the construction process on trees, and (4) Proposed Options 1, 2, and 3, and the South Street alternative are comparable, but are preferable to the Route 3A alternative, on the basis of initial street condition.

Accordingly, the Siting Council finds that, on balance, Proposed Options 1, 2, and 3, and the South Street alternative are preferable to the Route 3A alternative, on the basis of environmental impacts. The Siting Council further finds that Proposed Options 1 and 2, and the South Street alternative are comparable, but are slightly preferable to Proposed Option 3, on the basis of environmental impacts.

F. Reliability Analysis of the Proposed Facilities and Alternatives

The only reliability factor raised in this proceeding was the relative loads that each of the options and alternatives could serve.

Mr. Gilfeather stated that, in general, different pipeline routes would provide different capacities to Hingham Circle (Tr. II, pp. 165-166; Tr. V, pp. 56-58). Mr. Buckley asserted that there is no material difference in capacity between Proposed Options 1, 2, and 3 (Exh. BGC-5, p. 4). He noted, however, that Proposed Options 1, 2, and 3 would provide about five psig more pressure at the proposed Hingham Circle regulator station than the South Street alternative, a difference which he termed "significant" (Tr. VI, pp. 14, 33, 36, 45-46; see also Tr. II, pp. 153-154 and Tr. V, pp. 38-41). Mr. Silvestrini testified that the reduced pressure associated with the South Street alternative would reduce capacity additions in the Hull area by about 12 MCFH (Tr. VII, p. 8).

However, Mr. Gilfeather stated that the capacity provided by the alternatives that would connect to the feeder system upstream of the connection for Proposed Options 1, 2, and 3 -- e.g., the Route 3A alternative -- would have significantly greater inlet pressures and potentially greater capacities (Tr. II, pp. 165-166; Tr. V, pp. 56-58). The Company provided no analysis of the increase in delivery pressure or capacity that the Route 3A alternative would provide over Proposed Options 1, 2, or 3. Still, the record is clear that the Route 3A alternative would provide significantly more capacity than Proposed Options 1, 2, or 3, and the South Street alternative.[23]

Accordingly, the Siting Council finds that, on the basis of reliability, (1) Proposed Options 1, 2, and 3, are comparable, (2) Proposed Options 1, 2, and 3, are slightly preferable to the South Street alternative, and (3) the Route 3A alternative is preferable to Proposed Options 1, 2, and 3, and the South Street alternative.

G. Conclusions

The Siting Council has found that,

(1) on the basis of cost, Proposed Options 1, 2, and 3, and the South Street alternative are comparable, but are preferable to the Route 3A alternative,

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23/ Although the Company provided no analysis of the delivery pressure to Hingham Circle through the Route 3A alternative, inlet pressures where the Route 3A alternative would connect to the existing feeder system would be about 40 psig greater than the connection for Proposed Options 1, 2, and 3 (Exhs. HO-8, HO-17; Exh. BGC-2).

(2) on the basis of environmental impacts, (a) Proposed Options 1, 2, and 3, and the South Street alternative are preferable to the Route 3A alternative, and (b) Proposed Options 1 and 2, and the South Street alternative are comparable, but are slightly preferable to Proposed Option 3, and

(3) on the basis of reliability, (a) Proposed Options 1, 2, and 3, are comparable, (b) Proposed Options 1, 2, and 3, are slightly preferable to the South Street alternative, and (c) the Route 3A alternative is preferable to Proposed Options 1, 2, and 3, and the South Street alternative.

The Siting Council finds, however, that the cost and environmental advantages of Proposed Options 1, 2, and 3, and the South Street alternative outweigh the reliability advantages of the Route 3A alternative. The Siting Council has already found that Proposed Options 1, 2, and 3 have slight reliability advantages over the South Street alternative, that Proposed Options 1 and 2 have environmental impact advantages over Proposed Option 3, but that Proposed Options 1 and 2 are comparable on the basis of cost, environmental impacts, and reliability.

Accordingly, the Siting Council finds that, on balance, Proposed Options 1 and 2 are superior to Proposed Option 3, the South Street alternative, and the Route 3A alternative on the basis of cost, environmental impacts, and reliabilty. However, in order to address certain environmental impacts identified herein, the Siting Council ORDERS Boston Gas to comply with the conditions set forth in Section IV, infra.

In making this finding, the Siting Council must note that the Company's site evaluation process is substantially flawed. For instance, Mr. Tomlinson, the Company's witness, testified that, once potential load had been identified, "we went to the engineering department to ask them to find the cheapest way to meet those loads" (Tr. II, p. 167). Mr. Gilfeather agreed that his department had been asked to find the "best alternative" to serve the identified load, and therefore he had evaluated alternatives to find "the most effective means of serving the load from a cost-effective standpoint" (Tr. V, pp.

57-59). The Siting Council's enabling statute explicitly requires a balance between minimizing economic costs and environmental impacts in addressing an identified need. G.L. c. 164, sec. 69H. Although the Siting Council has found in this instance that the proposed facilities indeed minimize economic costs and environmental impacts, the Company is urged to review its siting process.

IV. DECISION AND ORDER

The Siting Council finds that construction of the proposed facilites along Proposed Options 1 or 2 and at Hingham Circle as described herein is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.[24]

The Siting Council hereby APPROVES the petition of Boston Gas Company and Massachusetts LNG, Inc. to construct a natural gas pipeline and regulator station subject to the following CONDITIONS:

(1) Boston Gas shall request a Determination of Effect from the Massachusetts Historical Commission pursuant to 950 CMR 71.00. Construction of the remainder of the proposed facilities may not commence until the Company (a) receives a Determination of Effect, (b) completes any necessary consultation process, and (c) notifies the Siting Council that the Company has received such determination and completed any necessary consultation process.

(2) During construction within the Proposed Local Historic District, Boston Gas shall (a) maintain at least eight feet of clearance between the edge of its trench and any structures, (b) for structures within 27 feet of the edge of the trench, provide for the installation and operation of equipment capable of monitoring vibrations at or of structures if the owner of that structure requests such equipment, (c) use saw-cut methods to open trenches, (d) use all reasonable methods to control dust, and (e) take all reasonable precautions to avoid removing or substantially damaging trees.

24/ While the Siting Council approves the Company's proposed facilities, the Siting Council has not found that such facilities are consistent with the Company's most recently approved forecast or supplement thereto (see Boston Gas Company, 16 DOMSC 173 (1987)). Until such time as Boston Gas receives approval of a forecast or supplement thereto which includes these proposed facilities, the Company cannot construct the remainder of the facilities.

(3) Prior to commencing construction of the remainder of the proposed facilities, Boston Gas shall (a) consult with appropriate town officials regarding street restoration, and (b) file a schedule for completing street restoration with appropriate town officials and with all parties to this proceeding. After completing construction, Boston Gas shall adhere to its schedule for restoration.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of May 26, 1988, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member); Madeline Varitimos (Public Environmental Member). Ineligible to vote: Stephen D. Umans (Public Electricity Member). Absent: Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Joseph W. Joyce (Public Labor Member).

Sharon M. Pollard
Chairperson

Dated this 26th day of May, 1988

TABLE 1

Boston Gas Company
Expected Load Growth
in Hull, Hingham, and Cohasset[a]
(CFH)

	1986 [b]	1987 [b]	1988	1989	1990	1991
Hull:						
Expected Growth	22,484	34,790	33,249	104,407	24,254	21,754
Added without Pipeline	22,484	0	0	0	0	0
Requires Add'l Capacity	0	34,790	33,249	104,407	24,254	21,754
Added w/Prop. Pipeline	---	34,790	33,249	81,961	0	0
Requires Cap. in Addition to Pipeline	0	0	0	22,446	24,254	21,754
Hingham:						
Expected Growth	13,022	26,731	77,160	25,250	19,150	19,150
Added without Pipeline	13,022	26,731	0	0	0	0
Requires Add'l Capacity	0	0	77,160	25,250	19,150	19,150
Added w/Prop. Pipeline	---	---	75,714	0	0	0
Requires Cap. in Addition to Pipeline	0	0	1,446	25,250	19,150	19,150
Cohasset:						
Expected Growth	2,058	5,354	1,775	1,775	1,775	1,775
Added without Pipeline	2,058	265	1,775	1,775	1,775	1,775
Requires Add'l Capacity	0	5,089	0	0	0	0
Added w/Prop. Pipeline	---	5,089	---	---	---	---
Requires Cap. in Addition to Pipeline	0	0	0	0	0	0

Notes: a. Based on connected load
b. Actual

Sources: Exhs. BGC-6, BGC-7

TABLE 2

Boston Gas Company
Estimated Lengths and Construction Costs
of Proposed Facilities and Alternatives

Alternative	Pipeline Length	Estimated Capital Cost	Difference From Lowest Cost
Proposed Option 1	7,680 ft	$ 1,370,000	$ 10,000 (0.7%)
Proposed Option 2	7,640	1,360,000	---
Proposed Option 3	7,820	1,400,000	40,000 (2.9%)
South Street Alt.	7,360	1,430,000	70,000 (5.1%)
Route 3A Alt.	14,500	2,600,000	1,240,000 (91%)
Lincoln Street Alt.	14,760	2,560,000	1,200,000 (88%)
Fottler Road Alt.	12,960	2,360,000	1,000,000 (74%)
Hingham Bay Alt.	24,000	11,700,000	10,340,000 (760%)
Railroad ROW Alt.	7,600	---	---

Notes:

a. Cost estimates are for both pipeline and regulator station construction including the Company's contingency margin.

b. Construction costs are exclusive of extra distribution system and service modifications necessary to place the 3,360 feet of pipeline in service prior to the 1987-88 heating season as noted in Section III.A.2.a, supra (Tr. VI, pp. 22-27).

Sources: Exhs. HO-1, HO-27, HO-51; Exh. BGC-3; Exh. HHC-9

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Middleborough Gas and Electric Department for Approval to Construct a 115 kV Electric Transmission Line	EFSC 87-18

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:

Robert J. Harrold
Brian G. Hoefler

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TABLES AND FIGURES:

The Energy Facilities Siting Council hereby APPROVES the supply plan of Middleborough Gas and Electric Department and CONDITIONALLY APPROVES the petition of Middleborough Gas and Electric Department to construct a new overhead 3.75-mile, 115 kV electric transmission line along the proposed route described herein.

I. INTRODUCTION

A. Summary of the Proposed Project and Facility

Middleborough Gas and Electric Department ("MGED" or "the Department") is a municipally-owned utility supplying gas and electricity to residential, commercial, and industrial customers in the Towns of Middleborough and Lakeville. The Department serves approximately 9,000 customers with annual energy consumption of approximately 130,000 megawatt-hours and a system peak of about 24 megawatts ("MW").

MGED is a member of the Massachusetts Municipal Wholesale Electric Company ("MMWEC") from which the Department receives planning and technical services. However, MGED's electricity supplies are delivered entirely through interconnections with Eastern Utilities Associates ("EUA").

MGED proposes to construct approximately 3.75 miles of new overhead 115 kV transmission line (see Figure 1) (Exh. M-1, p. 11). The proposed transmission line would operate in conjunction with an existing 115 kV line providing redundant service between the Department's Summer Street switching station and Wareham Street substation (id., Attachment 2-4). Under normal conditions, each line would carry about one-half of the Department's load (id.). The Department proposes to place the new transmission line within an existing, Department owned-and-operated electric right-of-way ("ROW") in the Town of Middleborough (id., p. 12). MGED estimated the capital cost of the proposed facility to be between $710,000 to $1,013,000 (Exhs. HO-1A, HO-1B).

B. Procedural History

On March 20, 1987, MGED filed an Occasional Supplement requesting approval to construct a 115 kV electric transmission line of 3.75 miles in length in the Town of Middleborough (Exh. M-1).

On June 30, 1987, the Siting Council conducted a public hearing in the Town of Middleborough. In accordance with the directions of the Hearing Officer, the Department provided notice of the public hearing and adjudication.[1]

On September 15, 1987, the Hearing Officer notified the Department that a pre-hearing conference would be scheduled to address the issue of whether MGED should be required to file an individual demand forecast and supply plan in light of the Siting Council's recent decision in Massachusetts Municipal Wholesale Electric Company, EFSC 85-1 (1987) ("MMWEC decision").[2]

On December 23, 1987, MGED filed (1) a memorandum in support of its Occasional Supplement ("pre-hearing memorandum") and (2) a supply plan. In its pre-hearing memorandum, the Department argued, among other things, that the MMWEC decision did not require the Siting Council to approve an individual MGED demand forecast and supply plan in order to approve MGED's proposed transmission line. The Department also requested that the Siting Council waive G.L. c. 164, sec. 69I, which requires that a facility proposal be consistent with an applicant's most recently approved forecast and supply plan.

On January 22, 1988, the Hearing Officer conducted a pre-hearing conference (1) to consider whether MGED should be required to file an individual demand forecast and supply plan, and (2) to establish a procedural schedule for the remainder of the proceeding. At the

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1/ The public hearing was initially scheduled for June 4, 1987. However, the Hearing Officer rescheduled the public hearing upon learning that the Department had failed to provide proper notice for the June 4 public hearing.

2/ The Siting Council issued its MMWEC decision on July 28, 1987. In that decision, the Siting Council approved MMWEC's demand forecast while rejecting its supply plan.

conference, the Hearing Officer ruled that, pursuant to G.L. c. 164, sec. 69I, and the Siting Council's MMWEC decision, MGED was required to file a supply plan to support its proposed facility. At the same time, the Hearing Officer also ruled that the Department was not required to file a demand forecast.

On March 9, 1988, the Siting Council conducted an evidentiary hearing. The Department presented six witnesses: Peter Thalmann, an engineering consultant; Mayhew Seavey, a power supply planning consultant; Charles H. McCrillis, manager of the electric division; Peter Wilbur, assistant manager of the electric division; Robert Ingram, an environmental consultant; and Leo Gillis, an engineering design consultant.

The Hearing Officer entered 129 exhibits in the record, largely composed of Department responses to information and record requests. MGED offered three exhibits.

Pursuant to a briefing schedule established by the Hearing Officer, the Department filed a brief on April 8, 1988.

C. Jurisdiction

The Company's Occasional Supplement is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, requiring electric companies to obtain Siting Council approval for construction of proposed facilities at a proposed site before a construction permit may be issued by any other state agency.

The Department's proposal to construct a 3.75-mile, 115 kV electric transmission line falls squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G:

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

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section III.A, infra). Next, the Siting Council requires the applicant to present plans that address the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section III.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply (see Section IV, infra).

D. MMWEC Decision and the Department's Supply Plan

In accordance with G.L. c. 164, sec. 69I, a "company shall not commence construction of a facility at a site unless the facility is consistent with the most recently approved long-range forecast or supplement thereto." On July 28, 1987, the Siting Council issued its MMWEC decision approving MMWEC's demand forecast while rejecting its supply plan. In reaching that decision on MMWEC as a whole, the Siting Council stated that its "findings on MMWEC's forecast and supply plan do not operate as an approval or rejection of the forecasts and supply plans of the member towns." Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95, 139 (1987). The Siting Council further noted that the MMWEC decision "would not preclude an MMWEC member from seeking the Siting Council's approval to construct a jurisdictional facility." Id.

In this proceeding, MGED, an MMWEC member, seeks the Siting Council's approval to construct a jurisdictional facility. The Department, however, argues that rejection of MMWEC's supply plan does not require the filing of an individual supply plan in order to obtain approval of the Department's proposed facility (Brief, p. 18). In particular, MGED submits that its facility proposal was filed four months prior to the Siting Council's MMWEC decision, and therefore was consistent with the "most recently approved long-range forecast or supplement thereto" at time of filing (id.). Finally, the Department argues that a "retroactive" application of the MMWEC decision would operate to violate MGED's due process rights (id., p. 19).

As part of this proceeding, the Hearing Officer has ruled that the Department is required to file an individual supply plan as a prerequisite to approval of its proposed facility. The Siting Council finds that the Hearing Officer's ruling is appropriate and denies the Department's request for a waiver of G.L. c. 164, sec. 69I.

G.L. c. 164, sec. 69I, requires that a jurisdictional facility be consistent with an approved forecast and supply plan. This statutory linkage between a facility and an approved forecast and supply plan is essential to ensure that facility proposals are developed in the context of reviewable, appropriate, and reliable forecasting techniques and adequate, least-cost supply planning. Absent this integration, the Siting Council cannot determine whether a facility proposal is necessary and cost effective.

While an MMWEC member typically might file a facility proposal for its system alone, an MMWEC member's demand forecast and supply plan are reviewed only as part of MMWEC's annual forecast filing. Therefore, in order to ensure that an MMWEC member's facility proposal has been developed in the context of acceptable demand forecasting and supply planning, the facility proposal, at a minimum, must be reviewed within the context of an approved MMWEC forecast and supply plan.

In its MMWEC decision, the Siting Council expressly held that its rejection of MMWEC's supply plan would not operate as a bar to the facility proposal of an MMWEC member. In this case, the Hearing Officer has required the Department to file an individual supply plan. While the Department argues that the requirement that a supply plan be filed amounts to retroactive application of the MMWEC decision, this requirement has no such effect. In fact, through a review of MGED's supply plan, the Siting Council can determine whether the Department's facility proposal is consistent with MGED's supply plan. Although MGED submits that this procedure violates certain due process rights, the Siting Council's review of this supply plan affords MGED the opportunity for full adjudicatory review of its facility proposal.

The Siting Council reviews the Department's supply plan in Section II, <u>infra</u>.

II. ANALYSIS OF THE SUPPLY PLAN

A. Standard of Review

In keeping with its mandate 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, sec. 69H, the Siting Council reviews three dimensions of an electric utility's supply plan: adequacy, diversity, and cost.

The adequacy of supply is a utility's ability to provide sufficient capacity to meet its peak loads and reserve requirements throughout the forecast period. Cambridge Electric Light Company, 12 DOMSC 39, 72 (1985); Boston Edison Company, 10 DOMSC 203, 245 (1984). The diversity of supply measures the relative mixture of supply sources and facility types. The Siting Council's working principle is that a more diverse supply mix, like a diversified financial portfolio, offers lower risks. Boston Edison Company, 15 DOMSC 287, 350 (1987). The Siting Council also evaluates whether a supply plan minimizes the cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Nantucket Electric Company, 15 DOMSC 363, 384-390 (1987). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. Boston Edison Company, 15 DOMSC 287, 339-349 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 136-138, 165-166 (1986). Finally, the Siting Council determines whether utilities treat all resources -- including demand management, conventional power plants, and purchases from cogeneration and small power projects and from other utility and non-utility suppliers -- on the same basis when attempting to develop an adequate, diverse, and least-cost supply plan.[3] Boston Edison Company, 15

3/ In 1986, the Massachusetts Legislature amended the Siting Council's statute to require the Siting Council to approve a company's forecast only if the Siting Council determines that a company has demonstrated that its forecast "include[s] an adequate consideration of conservation and load management." G.L. c. 164, sec. 69J.

DOMSC 287, 315-323 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 133-135, 151-155, 166 (1986).

Further, the Siting Council reviews the supply planning processes utilized by utilities. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council requires utilities' to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's consistent and systematic application of such criteria to supply planning decisions indicates that a company is evaluating new supply options in a manner that ensures an adequate supply of least-cost, least-environmental-impact power. These processes and criteria take on added importance when the dynamic nature of the energy generation market and the inherent uncertainty of projections make it difficult for a company to identify with exactitude all the power resources it plans to rely upon in the latter years of its long-range forecast. Nantucket Electric Company, 15 DOMSC 363, 378-379, 384, 390-391 (1987); Boston Edison Company, 15 DOMSC 287, 301, 322-323, 339-348 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 133-135 (1986); Fitchburg Gas and Electric Light Company, 13 DOMSC 85, 102 (1985).

The Siting Council has determined that different standards of review are appropriate and necessary to establish supply adequacy in the short run and the long run. Cambridge Electric Light Company, 15 DOMSC 125, 134 (1986).

To establish adequacy in the short run, a company must demonstrate that it has an identified, secure, and reliable set of energy and power supplies. In essence, the company must own or have under contract sufficient resources to meet its capability responsibility under a reasonable range of contingencies. If a company cannot establish that it has adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in being able to rely upon alternative supplies should necessary projects not develop as originally planned. Boston Edison Company, 15 DOMSC 287, 309-322 (1987); Cambridge Electric Light Company, 15 DOMSC 125, 134-135, 144-150, 165-166 (1986). The Siting Council has defined the short run as the period of time necessary to place into service sufficient resources obtainable from the shortest-lead-time resource option under a given company's control in a timely and cost-effective manner. The short run may vary on a company-by-company basis. Boston Edison Company, 15 DOMSC 287, 297, 307-308 (1987).

To establish adequacy in the long run, a company must demonstrate that its planning processes can identify and fully evaluate a reasonable range of supply options on a continuing basis while allowing sufficient time for the company to make appropriate supply decisons to ensure adequate, cost-effective energy and power resources over all forecast years. The Siting Council recognizes that the later years of the forecast may offer new, but as yet unknown, resource options which are both reliable and cost effective. The potential for these new resource options should increase in an electric generation and transmission market that adapts to a higher degree of uncertainty, becomes more competitive, and spawns projects which have shorter lead times. In formulating its standard for adequacy in the long run, the Siting Council recognizes this new energy environment and affords companies the opportunity to plan for their supplies in a creative and dynamic manner. Id., pp. 298, 313-320.

B. Supply Planning Process

MGED plans its supplies based on a minimization of revenue requirements subject to ensuring adequacy of supply (Exh. M-2, p. 5). The Department stated that its goals include long-run cost minimization, reduced oil dependence, diversity, and rate stability (id.). In its supply planning process, the Department first assumed an initial resource combination, then compared identified resource options to the initial resource combination (id., pp. 8-9). This comparison involved screening options with the Supply Screening Model, determining production costs by running POWRSYM, a production costing model, and using MGED's Revenue Requirements Model to calculate the revenue requirements of the resource combination (id., pp. 6-10).

The initial resource combination consisted of (1) all existing supply resources, and (2) certain "generic capacity additions" where projections of existing supply resources indicated insufficient supply to meet requirements projected by MGED's Demand Forecasting Model (id., pp. 2, 9). Generic capacity additions consisted of coal-fired, fluidized-bed power plants for baseload capacity and gas-fired combustion turbine power plants for peaking capacity (id., p. 9). Since MGED retained this initial resource combination as a basis for comparing other supply resources, the Department determined initial resource combination production costs and revenue requirements (id.).

To develop a least-cost supply plan, MGED identified other resource options and compared them to the initial resource combination to determine whether they would provide net benefits to the Department's customers (id., pp. 8-10). The Supply Screening Model evaluated an identified resource option by testing the sensitivity of the initial resource combination with that option to changes in key variables such as load growth, inflation, and fuel prices and by providing approximate production costs (id., pp. 6-7). For each identified resource option that met the screening criteria, the Department used its Production Costing Model to calculate more precise production costs of the initial resource combination with each particular option (id.). Based on these production costs, MGED determined the resultant revenue requirements from the Department's Revenue Requirements Model (id.). Next, MGED compared revenue requirements of resource combinations with and without each identified resource option in order to determine whether the options would reduce revenue requirements (id., pp. 9-10). If an option reduced revenue requirements, the Department updated its initial resource combination to include that option (id.).[4]

Thus, the Department asserted that its methodology resulted in a supply plan that is adequate, least cost, and diverse (id., p. 1).

4/ If the electricity prices generated by the Revenue Requirements Model varied significantly from those assumed in the demand forecast, MGED prepared a new demand forecast, recalculated production costs, and revised system revenue requirements (Exh. M-2, p. 8).

C. Adequacy of the Supply Plan

1. Adequacy of Supply in the Short Run

a. Definition of the Short Run

A company's short-run planning period is defined as the time required for a company to place into service resources under its direct control in sufficient quantities to meet the projected need for new capacity. MGED stated that its shortest-lead-time resource would be a 1 MW gas-fired diesel generating unit which can be placed in service in about two years (Tr., p. 130; Exh. HO-S-2).

Accordingly, for purposes of this review, the Siting Council finds that MGED's short-run planning period is two years extending through the winter of 1989-90.

b. Base Case Supply Plan

Table 1 compares MGED's projected capacity to its peakload capability responsibility for the forecast period. This Table indicates that MGED is projecting a short-run capacity surplus of about 44 percent during the winter of 1988-89 and about 54 percent during the winter of 1989-90.

Accordingly, the Siting Council finds that the Department has established that its base case supply plan is adequate to meet requirements in the short run.

c. Short-Run Contingency Analysis

MGED plans to add a new supply source, Seabrook 1, during the short run (Exh. M-2, Table E-17). If all other resources in its base case supply plan remain available to MGED, cancellation or delay of Seabrook 1 beyond MGED's short-run planning period would not cause a supply deficiency (see Table 2).

Accordingly, the Siting Council finds that MGED has established that it has adequate supplies to meet requirements in the short run in the event of a cancellation or delay of Seabrook 1.

2. Adequacy of Supply in the Long Run

MGED's long-run planning period is the remaining forecast horizon beyond the short run, from summer 1990 through power year 1996-97. Based on the Department's projected compound average annual increase in peakload growth of 2.5 percent over the 10-year period,[5] MGED's base case supply plan would satisfy capability responsibility and sales agreements throughout the long-run planning period (see Table 1).

As previously discussed in Section II.A, supra, the Siting Council requires an electric company to establish adequacy in the long run by demonstrating that its planning process can identify and fully evaluate a reasonable range of supply options. The ability of MGED's supply planning process to identify and fully evaluate a reasonable range of supply options is fully discussed from the perspective of least-cost supply planning in Section II.D, infra.

As indicated in Section II.D, infra, MGED has identified a reasonable range of supply options, but has failed to demonstrate that it fully evaluated those options. Accordingly, the Siting Council finds that MGED has failed to establish that its supply plan ensures adequate resources for its customers in the long run.

3. Conclusions on the Adequacy of Supply

The Siting Council has found that MGED (1) has established that its base case supply plan is adequate to meet requirements in the short run, (2) has established that it has adequate supplies to meet requirements in the short run in the event of a cancellation or delay of Seabrook 1, and (3) has failed to establish that its supply plan ensures an adequate supply of resources for its customers in the long run.

However, the Siting Council notes that MGED's base case supply

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5/ MGED's demand forecast was approved in Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987).

plan would satisfy capability responsibility and sales agreements throughout the long-run planning period (see Section II.C.2, supra). Accordingly, the Siting Council finds that, on balance, MGED has established that its supply plan ensures adequate resources to meet projected requirements.

D. Least-Cost Supply

1. Identification of Resource Options

MGED provided examples of the types of resource options it had identified for evaluation. The Department's witnesses, Mr. Seavey, Mr. McCrillis, and Mr. Wilbur, indicated that potential resource options for MGED include cogeneration, a small gas-fired "backyard unit," direct control of water heaters and central air conditioners by the Department, and installation of high-pressure sodium street lights (Tr., pp. 101, 117, 123, 128-130, 136-145). However, MGED failed to explain how it identified these and other resource options, stating only that its planning objectives focused on "improving fuel and unit diversity, improving system load factor, and optimizing power supply through short-term sales and exchanges of capacity" (Exh. HO-S-1).

Still, MGED identified several resource options for further evaluation, including both supply-side and demand-side options. Therefore, for purposes of this review, the Siting Council finds that MGED has identified a reasonable range of supply options.

2. Evaluation of Resource Options

a. Analysis of Resource Combinations

As described in Section II.B, supra, the Department's analysis of resource costs essentially determines the revenue requirements necessary to provide the energy and capacity associated with various resource combinations (Exh. M-2; Tr., pp. 101-104). The Siting Council finds that the basic structure of this analysis -- identifying combinations of resources, determining the revenue requirements associated with those combinations, then choosing the combination that minimizes revenue requirements -- is a reasonable approach to planning least-cost supplies for a company of the size and resources of MGED.

The Department provided an example of its resource option analysis based on its recent decision to sign a purchase agreement with Newbay Corporation for 2 MW of coal-fired capacity beginning in 1991 (Exh. HO-S-1). MGED stated that this decision was based on estimated power supply cost savings projected to be reduced by $1.9 million over 20 years (Tr., pp. 126-127; Exh. HO-S-1). However, the Department provided no evidence that it evaluated any other combinations of resources. For instance, MGED identified cogeneration and direct control of water heaters as potential resource options (see Section II.D.1, supra). Yet the Department provided no analyses of its projected revenue requirements based on resource combinations including either of these options. While the decision to purchase Newbay capacity may have yielded a combination of resources with lower revenue requirements than the initial resource combination, there may be other combinations of resources excluding Newbay capacity that would yield still lower revenue requirements. Thus, the Department's least-cost resource mix does not necessarily include the Newbay capacity purchase.

Although MGED described its methodology for analyzing costs associated with various resource combinations, MGED has not demonstrated that it has implemented this methodology and follows it when making supply decisions. Accordingly, the Siting Council finds that the Department's analysis of resource combinations fails to ensure that it identifies a least-cost resource mix.

b. Comparison of Resource Options on an Equal Footing

Mr. Seavey asserted that its supply planning methodology calculates demand-side capacity and energy benefits in a manner "equivalent" to calculations of supply-side benefits (Tr., pp. 123-124; see also Exh. M-2, p. 7). He noted that the Department uses the same methodology for analyzing demand-side and supply-side options, and cited the MGED's analysis of direct control water heaters as an example (Tr., pp. 123-124). In this analysis, the Department calculated the revenue requirements of a resource combination that included a program for direct control of water heaters, concluding that such a program would reduce revenue requirements (Tr., pp. 102-104).[6]

However, the record in this proceeding lacks sufficient evidence to demonstrate that MGED treats all resource options on an equal footing. First, the only two resource options which the Department has evaluated are the Newbay purchase and the program for direct control of water heaters. Without a demonstration of a more complete analysis of available options, the Siting Council cannot find that MGED has evaluated resources consistently. Further, of the two resource options that it has evaluated, the Department analyzed costs using different time horizons -- the Newbay facility was based on a 20-year period, while the direct control water heater program was based on a 10-year period (Exh. HO-S-1; Tr., p. 102). This type of inconsistency does not support the Department's assertion that it treats resources equivalently.[7]

Since the record in this proceeding neither supports nor refutes the Department's assertion that it treats resource options equivalently, the Siting Council makes no findings here regarding the comparison of resources on an equal footing.

c. Conclusions on Evaluation of Resource Options

The Siting Council has found that the Department's analysis of resource combinations fails to ensure that it identifies the least-cost resource mix, but has made no findings regarding whether the Department

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6/ Although the Department determined that a program for direct control of water heaters would reduce revenue requirements, Mr. Seavey indicated that prior to implementation the Department needed to study the program further (Tr., p. 126).

7/ The Siting Council notes that MGED's analysis of the Newbay facility indicated that the Department would not realize a net savings in revenue requirements until about 2001, the eleventh year of the analysis period (Exh. HO-S-1, Attachment S-1). Thus, under the 10-year horizon used for direct control of water heaters, the Department's Newbay analysis would not have identified any cost savings.

compared demand-side and supply-side options on an equal footing.

Accordingly, the Siting Council finds that the Department has failed to demonstrate that it fully evaluated a reasonable range of supply options.

3. Conclusions on Least-Cost Supply

The Siting Council has found that MGED has identified a reasonable range of supply options, but that the Department failed to demonstrate that it fully evaluated those resource options.

Accordingly, the Siting Council finds that MGED's supply plan does not ensure a least-cost energy supply.

E. Diversity of Supply

Based on information provided by MGED, supply resources encompass 16 separate units and eight fuel types (Exh. HO-S-5; Exh. M-2, p. 4, Table E-17). MGED indicated that it increased the diversity of its supply mix by adding the Newbay purchase, and that it intends to continue this diversifying trend (Exh. M-2, pp. 2, 5). Overall, MGED projected hydro-power's proportion of total supply to increase to about 13 percent by 1997, nuclear and natural gas to remain relatively constant over this time at about 37 percent and 21 percent, respectively, and coal to increase to about 10 percent (see Table 3). At the same time, MGED expects to reduce its dependence on oil from 34 percent in 1987 to 22 percent in 1997 (see Table 3).

Accordingly, the Siting Council finds that MGED has demonstrated that its supply plan is adequately diversified.

F. Conclusions on the Supply Plan

The Siting Council has found that MGED's supply plan (1) ensures adequate resources to meet projected requirements, (2) does not ensure a least-cost energy supply, and (3) is adequately diversified. However, the Siting Council notes that this supply plan is the first such document submitted by the Department. In addition, the Department has stated its intention to increase its analytical capabilites, and to apply these capabilities in evaluating resource options that are emerging in its service territory such as cogeneration and demand-side projects (Tr., pp. 143-145; Exh. M-2, p. 2).

Accordingly, in balancing these considerations, the Siting Council hereby APPROVES the supply plan of MGED.

III. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposals to construct energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources[8] to meet reliability or economic efficiency objectives. The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated 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 Council has found that new capacity is needed where projected future capacity available to the system is found to be inadequate to satisfy projected load and reserve requirements. Northeast Energy Associates, 16 DOMSC 335, 344-360, pp. 7-23 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); New England Electric System, 2 DOMSC 1, 9 (1977); Eastern Utilities Associates, 1 DOMSC 312, 312-314 (1977). With regard to contingencies, the Siting Council has found that new capacity is needed in order to

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

ensure that service to firm customers can be maintained in the event that a reasonably likely contingency occurs. Massachusetts Electric Company, 13 DOMSC 119, 137 (1985); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985); Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

2. Description of the Existing System

MGED is a winter-peaking system with a peakload that reached 23.6 MW during the winter of 1986-87 (Exh. HO-N-7). The Department forecasted increasing system-wide coincident peaks that are expected to reach about 28 MW by summer of 1997 (Exh. HO-8B).[9]

MGED receives its entire energy supply via 115 kV interconnections to EUA's transmission system (Exh. M-1, Attachment 2-1). MGED's energy supply originates at the EUA Bridgewater substation, and is transmitted on EUA's E-1 line from this facility to the MGED interconnection at the Summer Street switching station ("Summer Street switching station") (id., p. 8). From this station, the MGED M-1 line carries 115 kV energy 3.7 miles to MGED's only 115-to-13.8 kV substation at Wareham Street ("Wareham Street substation") from which supplies are distributed to customers on eight 13.8 kV feeders (Exh. M-1, p. 10). The M-1 line is capable of carrying at least 30 MW (Exh. HO-N-9A).

9/ The Siting Council approved this demand forecast in Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987).

3. Reliability

MGED stated that its firm power supply planning is based on single contingency design such that MGED's system "can withstand and continue to provide service with the loss of any major single piece of electrical equipment" (Exh. M-1, p. 22). MGED stated that customer outages and unacceptable electric system conditions can result from system operating conditions such as faults, unacceptable thermal loads, and unacceptable voltage conditions (id.). The Department noted that it applies this single contingency design standard without regard to the probability of system outage and duration (id.).

The Siting Council has found consistently that if the loss of any single major component of a supply system would cause significant customer outages, unacceptable voltage levels, or thermal overloads on system components, then there is justification for additional energy resources to maintain adequate system reliability. Hingham Municipal Lighting Plant, 14 DOMSC 7, 15 (1986); Boston Edison Company, 13 DOMSC 63, 70 (1985); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154 (1982); Commonwealth Electric Company, 6 DOMSC 33, 47 (1981); Middleborough Gas and Electric Department, 3 DOMSC 98, 101 (1979); Holyoke Gas and Electric Department, 3 DOMSC 1, 7 (1978).

The Department asserted that its 115 kV M-1 line between the Summer Street switching station and the Wareham Street substation prevents MGED from ensuring single contingency reliability (Exh. M-1, pp. 9-10). In particular, the Department asserted that if a fault occurs along this section, supplies must be switched to a 13.8 kV backup feeder which does not have sufficient capacity to carry MGED's full loads (id., p. 10).

This 13.8 kV backup line, known as the "North Middleborough feeder," emanates from EUA's Mill Street substation, and extends approximately 7.5 miles to the Wareham Street substation (id., pp. 25-26). MGED stated that thermal considerations limit power on this line to 8 MW (id., p. 10). Consequently, MGED asserted that using the North Middleborough feeder as a supply line requires load shedding if loads are greater than 8 MW (Exh. HO-N-9B). In addition, since the North Middleborough feeder lacks automated switching equipment, MGED estimated that switching service to this line requires four to six hours (Exhs. HO-N-1, HO-N-15; Tr., pp. 10, 12-13, 17).

MGED described contingencies that affected its power supply system in the past, including two instances within the last 12 years when its M-1 line was out of service for scheduled maintenance (Exh. HO-N-14). On each occasion, the entire MGED system was without service for approximately one hour (id.). MGED stated that, because of the difficulties in activating the North Middleborough feeder along with that line's inability to maintain reliable service, and since MGED personnel knew that 115 kV service would be restored in approximately one hour, the North Middleborough feeder was not placed in service during those scheduled maintenance operations (id.).

MGED provided load flow analyses of the activation of the North Middleborough feeder under actual peakload conditions during 1987, and peakload conditions projected for 1992 and 1997 (Exh. HO-N-9B). These analyses indicate load shedding could not be avoided if the North Middleborough feeder was activated as a replacement for MGED's M-1 line under peakload conditions (id.). In addition, MGED noted that system load did not fall below 8 MW during the past year, indicating that load shedding would essentially always be required if the M-1 line is shut down (Exh. HO-N-1).

Based on the foregoing, the Siting Council finds that MGED has demonstrated that its existing supply system is inadequate to satisfy existing and expected loads in Middleborough with acceptable reliability. Accordingly, the Siting Council finds that MGED has established that additional energy resources are needed in Middleborough.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H requires the Siting Council 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 lowest possible cost. In addition, G.L. c. 164, sec. 69I requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing, or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[10]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternative approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Northeast Energy Associates, 16 DOMSC 335, 360-380 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 212-218 (1986); Massachusetts Electric Company, 13 DOMSC 119, 141-183 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985).

2. Need

MGED proposes to construct an overhead 115 kV transmission line to provide redundant transmission service to the Wareham Street substation (Exh. M-1, pp. 11-12). MGED stated that its Wareham Street substation has the capacity to accommodate a second 115 kV line, and that the Wareham Street 115-to-13.8 kV transformer is capable of serving projected loads (id.).

MGED contended that its proposed project would provide capacity to supply MGED's load in case MGED's single existing 115 kV line experiences an outage (id.). In support of this contention, MGED stated that it would operate its system such that loads on its existing and proposed 115 kV lines would be about equal, each varying at peak from 12 to 15 MW (Tr., p. 14). MGED analyzed the proposed project under the contingency of the existing M-1 line being out of service (Exh. HO-N-9D). These analyses indicated that load of at least 30 MW could be supplied by the proposed project (id.). Since the Department proposes to install equipment to transfer loads automatically between the

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10/ G.L. c. 164, sec. 69I also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the petitioner's proposed site, as well as other site locations, in Section IV, infra.

existing and proposed 115 kV lines, any outage due to a fault on one of these lines would be momentary (Exh. HO-N-1). Thus, based on MGED's demand forecast, the proposed project would provide single contingency reliability until at least 1998 (Exh. M-1, Attachment 2-5).

MGED discussed three alternative approaches of addressing its single contingency reliability standard -- a low voltage alternative, conservation and load management ("C&LM"), and cogeneration (Exh. M-1, pp. 36-38; Exh. HO-N-4; Tr., pp. 136-139).

The low voltage alternative consists of expanding MGED's 13.8 kV interconnections with other utilities through the construction of additional feeders (Exh. M-1, pp. 18-19). MGED claimed that at least four more 13.8 kV backup feeders would be needed immediately and that additional feeders would be necessary 12 and 17 years later (id., p. 16). MGED maintained that after contacting all contiguous utilities, only EUA offered to supply service at 13.8 kV (id., p. 17). However, based on discussions with EUA, MGED observed that EUA's ability to provide service is limited (id.). EUA's transformer capability at its Mill Street substation currently would allow for approximately 12 MW of additional load growth which, counting the 8 MW already available to MGED, would total 20 MW for MGED (id.).[11] MGED further stated that EUA transformer capacity available for MGED would decrease annually as EUA's own load grows (id.).

MGED also considered a C&LM alternative. First, MGED noted that about 8 MW of backup capacity is available from its existing North Middleborough feeder through the low voltage system (id., p. 10). Hence, given an actual peakload of 23.6 MW during 1986-87, a C&LM alternative therefore would need to yield an additional 15.6 MW notwithstanding any future load growth. MGED concluded that this level of C&LM is unattainable in its service territory (Exh. HO-N-4).

As another project alternative, the Department has identified potential cogeneration development within its service territory (Tr., pp. 136-139). But although

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11/ EUA is capable of supplying at least 30 MW of power at the 115 kV level, but can supply only 20 MW at the 13.8 kV level (Exh. M-1, Attachment 2-10).

cogeneration potentially could address the identified need, the Department reported that no definite cogeneration projects are available at present within its service territory (id., pp. 126, 136-139).

The Siting Council finds that the Department has demonstrated that conservation and load management and cogeneration fail to address the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Council compares the proposal to the alternative project of expanding the low voltage system.

Further, the Siting Council finds that the proposed project is superior to the low voltage alternative with respect to addressing the identified need.

3. Cost

MGED asserted that its proposed project is the least-cost option for meeting the identified need for additional energy resources (Exh. M-1, p. 39). In support of this assertion, MGED presented a cost analysis based on the present worth of revenue requirements over 20 years for the proposed project and the low voltage alternative (id., Attachments 4-1, 4-2).

On the basis of this analysis, the Department estimated revenue requirements for the proposed project to be about $1,413,000 (Exhs. HO-1, HO-1A, HO-1B).[12] Revenue requirements for the low voltage alternative were estimated to be $4,502,000 (Exh. M-1, Attachment 4-2).

Accordingly, the Siting Council finds that the proposed project is superior to the low voltage alternative with respect to cost.

12/ Initially, the Department estimated revenue requirements for the proposed project to be $1,185,000 (Exh. M-1, Attachment 4-1). However, during the course of this proceeding, an oral agreement was reached between EUA and MGED on facilities modification arrangements for the EUA Bridgewater substation that are necessary to provide the proposed service (Exh. HO-1). Thus, revenue requirements estimated for the proposed project ranged from $1,323,000 to $1,413,000 depending upon the circuit breaker capital cost/facility charge option selected by MGED (Exhs. HO-1, HO-1A, HO-1B).

4. Environmental Impacts

MGED claimed that its proposed project minimizes environmental impacts (Exh. M-1, pp. 45-78). In support of this claim, MGED offered a comparison between its proposed project and the low voltage alternative in terms of visual effects and land resource impacts including potential wetland impacts (id.).

MGED asserted that the proposed project is superior to the low voltage alternative with respect to visual effects for three reasons: (1) 13.8 kV lines use closer pole placements than 115 kV lines, (2) the low voltage alternative requires at least four separate feeders compared to one for the proposed project, and (3) the low voltage alternative requires at least 24.2 miles of construction compared to 5.0 miles or less for the proposed project (Exh. HO-E-14). However, in making this comparison, the Department failed to consider increased visual effects associated with the proposed project due to construction of poles taller than those associated with the low voltage alternative. Nevertheless, the Siting Council finds that the visual attributes of the low voltage alternative, involving both more poles and more separate lines would result in greater visual effects than the taller poles required by the proposed project.

For similar reasons, MGED claimed that land resource impacts, particularly in regard to wetlands, would be greater under the low voltage alternative (id.). The Department noted that its service territory consists of nearly 100 square miles including numerous wetland areas (Exh. M-1, p. 3, Attachments 5-9, 5-10). Consequently, the more numerous pole placements associated with the low voltage alternative present a greater likelihood of impacts to land in general and wetlands in particular. While the Department failed to address other land resource impacts such as total incremental clearing of existing ROW and possible acquisition and clearing of new ROW, these impacts would also tend to be greater as the total length of new construction increases. Given the 24.2 miles of construction under the low voltage alternative as opposed to 5.0 miles or less under the proposed project, the low voltage alternative would likely result in greater land resource impacts than the proposed project.

Accordingly, the Siting Council finds that the proposed project is superior to the low voltage alternative with respect to environmental impacts.

5. Conclusions: Weighing Need, Cost, and Environmental Impacts

The Siting Council has previously found that (1) the proposed project is superior to the low voltage alternative with respect to addressing the identified need, (2) the proposed project is superior to the low voltage alternative with respect to cost, and (3) the proposed project is superior to the low voltage alternative with respect to environmental impacts.

Accordingly, the Siting Council finds that MGED has demonstrated that its proposed project is consistent with ensuring a necessary energy supply with a minimum impact on the environment at lowest possible cost.

IV. ANALYSIS OF THE PROPOSED FACILITY

A. Standard of Review

G.L. c. 164, sec. 69I requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternative approaches in terms of cost, environmental impacts, and addressing identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 195-196, 229-237 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986); Massachusetts Electric Company, 13 DOMSC 119, 183-184, 190-248 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 76-81 (1985).

B. Description of the Proposed Facility and Alternatives

1. Proposed Facility

The Department proposes to construct approximately 3.75 miles of overhead 115 kV line within an existing MGED owned-and-operated ROW (Exh. M-1, p. 46). This ROW currently contains MGED's 115 kV M-1 line and the North Middleborough feeder (id.). The proposed line would be placed between these two existing lines and situated about 95 feet from the west edge of the ROW and about 55 feet from the east edge (see

Figure 2) (id., Attachment 2-6; Tr., p. 79). The proposed facility would be located entirely in the Town of Middleborough and would travel in a generally north-south direction interconnecting the Summer Street switching station with the Wareham Street substation (Exh. M-1, Attachments 2-2, 2-4). Vertical poles are envisioned for the proposed line consisting of approximately 70-foot-tall single poles with davit arms (id., Attachment 2-6). For the proposed facility MGED estimated that revenue requirements would be about $1,413,000 and that capital costs would be about $1,005,000 (Exh. M-1; Exhs. HO-1, HO-1A, HO-1B).

Figure 1 indicates the location of the proposed facility. The proposed route would begin at the Summer Street switching station, the route's northern terminus, near Murdock Street and Summer Street (Exh. M-1, Attachment 5-1). From this point, the route would travel generally south crossing Beaverdam Brook, Plain Street, Precinct Street, a KOA campground, and Highway 44 (id.). South of Highway 44, the route would cross the Nemasket River and then turn southeast (id.). Continuing east of Middleborough Center, it would recross the Nemasket River, cross East Main Street, and traverse a hilly area (id.). Finally, the route would turn generally west, crossing the Nemasket River twice over the final 5/8 mile until reaching the Wareham Street substation, the proposed southern terminus of the route (id.).

2. Commonwealth Alternative

The "Commonwealth alternative" consists of approximately 4.2 miles of overhead 115 kV line using Department owned-and-operated ROW, other electric utility ROW, and segments of new ROW (Exhs. HO-E-23, HO-6A). Similar to the proposed facility, the Commonwealth alternative would interconnect the Summer Street switching station and Wareham Street substation, and would be located entirely within the Town of Middleborough (id.). MGED estimated that the capital costs of the Commonwealth alternative would be about $1,580,000 (Exh. M-1, Attachment 4-2; Exh. HO-6B).

Figure 1 indicates the location of the Commonwealth alternative. Beginning at the the Summer Street switching station, the Commonwealth alternative would run generally southeast for about 1.5 miles, parallel and adjacent to a Commonwealth Electric Company ("Commonwealth") ROW (Exhs. HO-E-23, HO-6A). After crossing Plain Street and Precinct Street, this alternative would depart from the Commonwealth ROW, angling to the south and establishing about 1.75 miles of new ROW (id.). This new ROW would cross Meetinghouse Swamp, Route 44, and Plymouth Street before joining MGED's ROW about 400 feet north of East Main Street (id.). The remaining 0.9 mile of the Commonwealth alternative would continue generally west along the same MGED ROW route as the proposal including two crossings of the Nemasket River, eventually terminating at the Wareham Street substation (id.).

3. Underground Alternative

MGED briefly described an underground transmission alternative consisting of a 115 kV line along the same route as the proposal (see Figure 1) (Exh. M-1, p. 78). MGED noted that trenching would cause "extreme disruption" to land resources, and asserted that it would be "much more difficult to maintain" when compared to an overhead configuration (id.). The Department did not provide an estimate of capital costs or revenue requirements for this alternative.

C. Site Selection Process

MGED indicated that several types of environmental impacts might be considered when siting transmission facilities. Such impacts include visual effects, wetlands impacts, existing versus virgin ROW, easement rights, and presence of access roads for construction and maintenance (Exhs. HO-6, HO-6A; Exh. M-1, pp. 54-58). In addition, the Department stated that both cost and the time necessary to acquire easements and permits are important factors to consider (Exhs. HO-E-23, HO-6).

However, while MGED identified a variety of factors that might be helpful in appraising sites, the Department presented no evidence that it developed and systematically applied specific criteria within an established site selection process. Although detailed analysis of all conceivable options is not necessary in the early stages of facilities screening, the Siting Council has a well-established policy of requiring applicants (1) to examine a reasonable range of practical facility siting alternatives, and (2) to demonstrate that the proposed facilities are superior to alternatives on the basis of a balancing of cost, environmental impact, and reliability of supply. Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 195-196, 229-237 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986); Massachusetts Electric Company, 13 DOMSC 119, 183-184, 190-248 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 76-81 (1985).

G.L. c. 164, sec. 69I, and 980 CMR 7.04(8)(c), as implemented through Siting Council Administrative Bulletin 78-2, explicitly require consideration of at least one practical facility alternative. The only facility alternative even mentioned by MGED in its Occasional Supplement was the underground alternative which the Department dismissed without any detailed analysis. In fact, the Department appropriately screened out this alternative since aspects of it such as underground construction through significant archaeological sites (see Section IV.E.3, infra) clearly indicate that it is not a practical facility alternative. Thus, MGED identified no practical facility alternatives.

The Siting Council finds that the Department has failed to establish that it developed and applied a reasonable set of criteria for identifying possible sites for its proposed transmission line. Failure to develop and apply such criteria in accordance with the Siting Council's standards could lead to a finding that a facility proponent had failed to consider a reasonable range of practical facility alternatives. During the course of this proceeding, however, the Siting Council staff identified the Commonwealth alternative. The initial siting and cost information as described in Section IV.B.2, supra, indicate that this alternative is a practical facility alternative and warrants further review. Hence, a practical facility alternative was raised and considered during the proceeding.

Although the obligation to identify and consider practical facility alternatives lies with a facility proponent rather than the Siting Council staff, for purposes of this review, the Siting Council finds that MGED has considered a reasonable range of practical facility alternatives.

D. Cost Analysis of the Proposed Facility and Alternative

MGED calculated total capital costs for the proposed facility to be about $1,005,000 (Exh. M-1, p. 43). For the Commonwealth alternative, MGED identified about $575,000 in capital costs in addition to those associated with the proposed route indicating that the Commonwealth alternative would cost about 57 percent more to construct than the proposal (Exh. HO-6B). These additional capital costs include $375,000 for land acquisition, $90,000 due to the greater length, and $110,000 for miscellaneous costs (id.). In addition, MGED stated that these alternative facility costs do not include additional costs associated with clearing or access road construction (Exhs. HO-6A, HO-6B).

Accordingly, the Siting Council finds that, on the basis of cost, the proposed facility is preferable to the Commonwealth alternative.

E. Environmental Analysis of the Proposed Facility and Alternative

During the proceeding, MGED provided analyses of the expected environmental impacts of the proposal and Commonwealth alternative including possible measures to mitigate such impacts (Exh. M-1, pp. 45-78; Exh. HO-6A). In its review, the Siting Council first determines whether the proposal and alternative would be acceptable with respect to its expected environmental impacts.[13] Boston Gas Company, EFSC 86-25A, pp. 26-31 (1988); Northeast Energy Associates, 16 DOMSC 335, 391-407 (1987). The Siting Council then compares the proposal and the alternative to determine which plan is preferable in terms of having a minimum impact on the environment (see Section IV.A, supra).

Potential environmental impacts identified during this proceeding

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13/ Before approving proposed facilities, the Siting Council must determine that the proposed facilities are "consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." G.L. c. 164, sec. 69J.

were related to wetlands, wildlife, archaeological resources, waterways, visual effects, and electrical effects. The Siting Council reviews these impacts in its analysis of the proposed facility and alternative.

1. Wetlands

The Department discussed the wetlands impacts of its proposal and the Commonwealth alternative in terms of total wetlands area affected, pole placements, and availability of access roads.

As characterized by the Department, the proposed facility would include 6,530 feet of wetland crossings while the Commonwealth alternative would cross about 4,300 feet of wetlands (Exhs. HO-E-23, HO-6A). Thus, in terms of absolute distance, the Commonwealth alternative would require shorter lengths of wetland crossings.

However, MGED argued that distance alone would not be an adequate measure of total wetlands area affected (Exh. HO-E-23). For instance, MGED stated that an important aspect of the proposed wetlands crossings is that such crossings would be restricted to an existing, cleared ROW, while the wetlands crossings required by the Commonwealth alternative would disrupt previously undisturbed wetlands in order to create new ROW (id.). In addition, the Department estimated that the proposed facility would not require any wetlands clearing, while the Commonwealth alternative would require 6.37 acres of wetlands clearing all of which would be in undeveloped territory (Exh. HO-6A). Hence, the Department contended that construction of the Commonwealth alternative would result in greater overall impacts to wetlands than the proposed facility (id.).

The Siting Council agrees that the type and extent of wetlands impacts associated with the Commonwealth alternative outweigh any of its advantages due to the shorter length of wetlands crossings.

In terms of pole placements, MGED asserted that the proposed facility would generate fewer impacts to wetlands than the Commonwealth alternative (Exh. M-1, pp. 64-65; Exh. HO-E-23). The most extensive impacts are expected to occur in Wetland Number 8 with four wooden pole placements and Wetland Number 11 with a single steel pole set in a concrete foundation (Exh. M-1, pp. 66-68). MGED estimated that the area of permanent wetlands alteration due to pole placements would be about

75 square feet under the proposal (Exh. HO-6A). Regarding the Commonwealth alternative, the Department estimated that this alternative would require a total of 12 pole placements within wetlands resulting in up to 150 square feet of permanent wetlands alterations (id.). The most extensive impacts of the Commonwealth alternative would occur along the new ROW in a 2,300-foot section of Meetinghouse Swamp (about five poles) and in a 1,400-foot section of wetlands east of Precinct Street (about three poles) (Exh. M-1, Attachment 5-2; Exh. HO-6A).

Thus, the Department has provided sufficient evidence to indicate that wetlands impacts due to pole placements would be less extensive under the proposal than under the Commonwealth alternative.

MGED asserted that a further wetlands consideration is that construction of the Commonwealth alternative would engender even greater wetlands impacts due to the absence of access roads (Exh. HO-E-23). Since 4,700 feet of the Commonwealth alternative would pass through wetland areas which are currently undeveloped, construction of the Commonwealth alternative would first require access-road construction through these wetland areas (id.). In contrast, the Department stated that the proposed facility would avert additional wetlands impacts because all necessary access roads already exist (Exh. HO-E-9). This consideration is a further indication that the proposal would result in less extensive wetlands impacts than the Commonwealth alternative.

MGED suggested general methods to reduce wetlands impacts by using such mitigation measures as hay bales, silt fences, and swamp mats (Exh. M-1, pp. 65-67). The Department stated that it would employ such measures as necessary in order to "satisfy the most stringent standards under the Wetlands Protection Act" (id., p. 48). In addition, the Department stated that it would revegetate any disturbed areas (id., p. 49).

With the mitigation measures proposed by the Department, the Siting Council finds that both the proposed facility and the Commonwealth alternative would have acceptable impacts on wetlands. Based on the foregoing, the Siting Council finds that the proposal is preferable to the Commonwealth alternative with respect to wetlands impacts.

2. Wildlife

MGED noted that the eastern box turtle, which is listed as a Species of Special Concern by the Massachusetts Natural Heritage Program ("MNHP"), has been reported along the route of the proposal (Exh. M-1, p. 75). The Department did not indicate whether the eastern box turtle had been sighted along the Commonwealth alternative.

In response to Department inquiries, MNHP recommended that alterations to wetland habitats be kept to "a strict minimum" and that any sightings be reported to the MNHP (id., Attachment 5-10). MGED's witness, Mr. Ingram, stated that "the minimal impact on wetlands that we will be having by limiting the wetland encroachments and wetland activities has only negligible insignificant potential for impact on the box turtle in terms of its overall breeding and feeding habits" (Tr., p. 53). In addition, MGED indicated that construction crews would be alerted to the presence of this species and would receive copies of a MNHP "Fact Sheet" which explains how to identify the eastern box turtle, and that the Department would report any sightings to MNHP (Exh. M-1, p. 75).

Accordingly, with the mitigation measures proposed by the Department, the Siting Council finds that both the proposed facility and the Commonwealth alternative would have acceptable impacts on wildlife.

3. Archaeological Resources

MGED submitted an inquiry to the Massachusetts Historical Commission ("MHC") regarding historical and archaeological resources along the proposed transmission route (Exh. M-1, Attachment 5-12). In response, MHC identified four archaeological sites within the existing transmission line easement, and requested that the Department conduct an intensive archaeological survey pursuant to 950 CMR 70 in order to locate and identify important archaeological resources which might be affected by the proposed facility (id.).

The Department retained a consultant to conduct such a survey (Exh. HO-2A). This consultant found that the proposed transmission corridor "had been intensively utilized by both prehistoric and historic period populations" and identified three significant archaeological sites that could be affected by the proposed facility (id., pp. 51-52). The Department's consultant recommended several measures to mitigate any effects to these three areas including (1) relocating transmission line poles to locations found to be archaeologically sterile, (2) clearly marking the areas on construction plans as restricted and protected, (3) flagging the areas during construction, and (4) planning equipment entry and exit routes so as to avoid the areas (id., p. 56).

Accordingly, the Siting Council finds that, with the mitigation measures recommended by the Department's consultant, the proposed facility would have an acceptable impact on archaeological resources.

4. Waterways

The proposed facility would cross the Nemasket River four times while the Commonwealth alternative would cross this river two times (see Section IV.B, supra). MGED noted that the Nemasket River has been classified as a Recreational Urban River under the Massachusetts Scenic and Recreational Rivers Program (Exh. HO-E-4). MGED further noted that, although the Nemasket River has been classified, no state regulations have been promulgated regulating its use (id.).

Recreational uses of the Nemasket River identified by the Department included canoeing, fishing, walking, and bird watching (Exh. HO-E-15). MGED claimed that the existing 115 kV line spanning the Nemasket River has caused no interference with any of the river's recreational uses (id.). MGED provided that the overhead clearance of the new line would be identical to that of the existing line and therefore similarly would not interfere with any recreational uses (id.). The Department also stated that it expects no construction or maintenance impacts on the river since access roads already exist for the proposed ROW (Exh. HO-E-9).

Accordingly, the Siting Council finds that both the proposed facility and the Commonwealth alternative would have acceptable impacts on waterways. Since the proposed facility would involve two more crossings of the Nemasket River than the Commonwealth alternative, the Siting Council finds that the proposal is slightly less preferable than the Commonwealth alternative with respect to waterways impacts.

5. Visual Effects

MGED asserted that the visual impacts of a new transmission line would not significantly affect the scenic character of a ROW which already has a transmission line (Exh. M-1, p. 58). In order to appraise the visual impacts of the proposed facilities, the Department established a visual impact analysis methodology. The Department first set out criteria for assessing the scenic quality of the affected environment. Next, MGED established criteria for ascertaining the extent of transmission line visual impacts and defined field conditions which reduce these visual impacts (id., p. 57). Finally, the scenic quality factors were integrated with the visual impact criteria and mitigating field conditions to generate an impact ranking (id., p. 58).

Based on this analysis, MGED predicted the greatest visual impacts along (1) the "Plain Street to Precinct Street" segment which offers varying views of the ROW from nearby residential homes that are on average 500 feet from the ROW, (2) the "Precinct Street Field" segment which consists a 650-foot open wetland meadow crossing and varying residential views of the ROW, (3) the "Precinct Street to Plymouth Street" segment which includes crossings of a campground and Highway 44, (4) the "Nemasket River Crossing to East Main Street Rt. 105" segment where residential homes and a small business are afforded views of the ROW, and (5) the "East Main Street Rt. 105 Parallel to Station Number 261" segment where adjacent land includes residences, commercial businesses, and a scenic view of the Nemasket River from the East Main Street Bridge (id., pp. 59-61).

However, the Department contended that these visual impacts are still minor and acceptable for two reasons. First, the proposed facility would be constructed along an established ROW; second, the Department would take certain measures to minimize incremental impacts such as (1) using wooden structures for 38 of the poles while using steel structures for the remaining four, (2) aligning new towers with those existing, and (3) matching the powerline sag between towers (Exh. HO-E-22; Exh. M-1, p. 50).

Even so, the Department acknowledged that, since its proposal would use single-pole, davit-arm structures, they would be about 15 feet higher than the existing horizontal poles (see Figure 2) (Tr., p. 64; Exh. M-1, pp. 13-14; Exh. HO-E-22). MGED stated that it would be impossible to match the existing horizontal poles since the proposed facility would be placed between the existing 115 kV M-1 line and 13.8 kV North Middleborough feeder, a space too restrictive to allow horizontal poles (see Figure 2) (Exh. HO-E-20). Nevertheless, the Department asserted that the proposed pole and sag alignments would minimize incremental "skyline view" impacts (id.).[14]

With respect to the Commonwealth alternative, MGED argued that this alternative would present significant visual impacts since it would introduce a new transmission line into a previously undeveloped region (Exh. HO-6A). The Department observed that the Commonwealth alternative would require about 9,100 feet of virgin ROW compared to no virgin ROW footage for the proposed facility (id.). In addition, the Department noted that the Commonwealth alternative would be about 2,300 feet longer overall than the proposed facility thereby eliciting more extensive visual impacts (id.).

Given the construction plans proposed by the Department, the Siting Council finds that both the proposed facility and the Commonwealth alternative would have acceptable visual impacts.

In previous decisions, the Siting Council has found that the use of existing ROW generally is preferable to establishing new ROW when siting electrical transmission line facilities. Massachusetts Electric Company, 13 DOMSC 119, 191-192 (1985); Boston Edison Company, 3 DOMSC 44, 53-55, 61-64 (1978). In the instant case, the visual impacts associated with establishing a new ROW under the Commonwealth alternative are clearly more extensive than the incremental visual impacts to the existing transmission ROW under the proposal.

14/ MGED noted that its North Middleborough feeder serves as the only backup supply presently available, and therefore the Department does not plan to remove this line until a new line is placed in service (Exh. HO-E-20). Thus, no additional space is available on the proposed ROW (id.). See Figure 2.

Accordingly, the Siting Council finds that the proposed facility is preferable to the Commonwealth alternative with respect to visual impacts.

6. Electrical Effects

MGED estimated electric and magnetic field levels associated with the proposed facilities (Exh. HO-5).

Based on literature and field testing of similar circuits, MGED provided expected electric field levels in kV per meter ("kV/m") at varying distances from the centerline of the new circuit towards the nearest edge of the ROW (Exh. HO-E-7). These electric field levels are summarized in Table 4. Table 4 indicates that the edge-of-ROW electric field levels for the narrowest ROW sections of the proposal -- about 50 feet from centerline -- would be on the order of 0.3 kV/m.

MGED also calculated expected magnetic field levels associated with the proposed facilities (see Table 4) (Exh. HO-E-5). According to these calculations, magnetic fields under the highest electrical current scenario would be about 5.5 milligauss ("mG") on the east edge of the narrowest ROW sections and 11.2 mG on the west edge (id.). In every scenario analyzed, the Department estimated reductions in magnetic fields with the proposed facilites compared to the existing system (id.). MGED attributed these reductions to its plan to split the electrical current between the existing and proposed lines as opposed to the present case of using just the existing line (id.).

The Department did not provide estimates of electric or magnetic field levels for the Commonwealth alternative.

MGED asserted that studies have not shown any correlation between adverse health effects and close proximity to electric and magnetic fields (Exh. M-1, p. 77). In addition, MGED claimed that the distances between the lines and the nearest residence are such that the likely field electrical effects appear to be significantly below edge-of-ROW levels set by the EFSC in its decisions regarding Hydro Quebec Phase II (Massachusetts Electric Company, 13 DOMSC 119 (1985)) and Hingham Municipal Lighting Plant, 14 DOMSC 7 (1986) (Exh. M-1, p. 77). Although the Siting Council notes that it has not "set" edge-of-ROW electric or magnetic field levels in any previous decision, in its decision regarding Hydro Quebec Phase II, the Siting Council accepted the proposed maximum edge-of-ROW electric field levels of 1.8 kV/m and proposed maximum edge-of-ROW magnetic field levels of 85 mG. Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985). In the instant case, the proposed facility would induce electric and magnetic fields below the Hydro Quebec Phase II levels (see Table 4).

Based on the record in this proceeding, the Siting Council finds that the proposed facility and its alternative would have acceptable impacts with respect to electrical effects. The Siting Council further finds that the proposed facility and the Commonwealth alternative are comparable with respect to electrical effects.

7. Conclusions on Environmental Impact

The Siting Council finds that the proposal and Commonwealth alternative will have an acceptable impact on all of the environmental concerns raised in this proceeding.

The Siting Council has found that (1) the proposal is preferable to the Commonwealth alternative with respect to wetlands impacts, (2) the proposal and the Commonwealth alternative are comparable with respect to archaeological resource impacts, (3) the proposal is slightly less preferable than the Commonwealth alternative with respect to waterways impacts, (4) the proposal is preferable to the Commonwealth alternative with respect to visual impacts, and (5) the proposal and the Commonwealth alternative are comparable with respect to electrical effects.

Accordingly, the Siting Council finds that, on balance, the proposed facility is preferable to the Commonwealth alternative with respect to environmental impact.

F. Reliability Analysis of the Proposed Facility and Alternative

The record in this proceeding is silent on the question of whether the reliability of the proposed transmission plan is preferable to that of the Commonwealth alternative.

Accordingly, the Siting Council finds that there is no preference between the proposal and the Commonwealth alternative on the basis of reliability of supply.

G. Conclusions on the Proposed Facility

The Siting Council has found that MGED has considered a reasonable range of practical facility alternatives. In addition, the Siting Council has found that the proposed facility is preferable to the Commonwealth alternative on the basis of both cost and environmental impact, but that there is no preference between the proposal and the Commonwealth alternative on the basis of reliability of supply.

Based on the foregoing, the Siting Council finds that, on balance, the proposed facility is superior to the Commonwealth alternative on the basis of cost, environmental impact, and reliability of supply. However, in order to address certain environmental impacts identified herein, the Siting Council ORDERS MGED to comply with the conditions set forth in Section V, *infra*.

V. DECISION AND ORDER

The Siting Council hereby APPROVES the supply plan of Middleborough Gas and Electric Department.

Further, the Siting Council finds that construction of the proposed facility along the proposed route described herein is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Council further finds that the proposed facility is consistent with the Department's most recently approved forecast.[15]

Accordingly, the Siting Council hereby APPROVES the petition of Middleborough Gas and Electric Department to construct a 115 kV electric transmission line subject to the following CONDITIONS:

(1) The Department shall alert construction workers of the potential presence of eastern box turtles and provide information on how to identify them. As soon as practicable, the Department shall report any sightings of the eastern box turtle to the Massachusetts Natural Heritage Program.

(2) The Department shall follow all the recommendations of its archaeological consultant including, but not limited to, (a) placing poles in locations found to be archaeologically sterile, (b) clearly marking areas of archaeological significance on construction plans as restricted and protected, (c) flagging areas of archaeological significance during construction, and (d) planning equipment entry and exit routes so as to avoid areas of archaeological significance. The Department shall also comply with any recommendations of the Massachusetts Historical Commission.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

Dated this 30th day of June, 1988

15/ In this case, the Department's "most recently approved forecast" comprises the demand forecast approved in Massachusetts Municipal Wholesale Electric Company, 16 DOMSC 95 (1987), and the supply plan approved in Section II, *supra*.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of June 30, 1988, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic Affairs); Paul Romary (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Stephen D. Umans (Public Electricity Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Labor Member); Madeline Varitimos (Public Environmental Member).

Sharon M. Pollard
Chairperson

Dated this day of June 30, 1988

TABLE 1

Middleborough Gas and Electric Department
Consolidated Demand Forecast and Supply Plan
Summer and Winter Peaks (MW)

Year	Estimated Capability Respons. Summer	Total Supply	Surplus/ (Deficit)	Estimated Capability Respons. Winter	Total Supply	Surplus/ (Deficit)
1988	24.1	28.5	4.4	24.6	35.4	10.8
1989	24.8	34.5	9.7	25.4	39.2	13.8
1990	25.6	37.9	12.3	25.7	37.5	11.8
1991	25.8	37.9	12.1	26.4	37.9	11.5
1992	26.6	36.4	9.8	27.2	37.9	10.7
1993	27.3	36.4	9.1	27.9	37.9	10.0
1994	28.1	36.3	8.2	28.8	36.1	7.3
1995	29.1	35.5	6.4	29.7	39.5	9.8
1996	29.6	36.2	6.6	30.3	39.5	9.2

Source: Exh. HO-8B

TABLE 2

Middleborough Gas and Electric Department
Short-Run Contingency Analysis
Winter Peak Load (MW)

Cancellation or Delay of Seabrook 1[a]

Year	Base Case[b] Surplus (Deficit)	Loss of Seabrook 1	Contingency Surplus (Deficit)
1988-89	10.75	0	10.75
1989-90	13.80	(5.37)	8.43

Notes:

a. The Department assumed it would begin receiving its Seabrook 1 entitlement of 5.37 MW in Winter 1989-90.

b. See Table 1 for short-run base case surplus/deficit.

Source: Exh. HO-8B

TABLE 3

Middleborough Gas and Electric Department
Fuel Diversity

FUEL TYPE	1987	1992	1997
Hydro	8%	15%	13%
Unenriched Uranium	19	0	0
Enriched Uranium	18	39	35
Coal	0	11	10
Natural Gas	21	22	20
#6 Oil (2.2%)	20	10	4
#6 Oil (1% and 0.5%)	12	2	4
#2 Oil	2	1	14

Source: Exh. HO-S-5

TABLE 4

Middleborough Gas and Electric Department
Estimated Electric and Magnetic Field Levels

ELECTRIC FIELDS

Distance Toward Nearest Edge of ROW	Expected Electric Field
25 feet	0.7 kV/m
50	0.3
75	0.1
100	0.1

MAGNETIC FIELDS

1. Existing System (1 circuit)

ROW Width	Load Level	West Edge of ROW	East Edge of ROW
150 ft.	Present	1.9 mG	7.1 mG
	20 Years	2.8	10.1
100 ft.	Present	11.5	4.7
	20 Years	16.4	6.8

2. Existing System with Proposed Facility (2 circuits)

ROW Width	Load Level	West Edge of ROW	East Edge of ROW
150 ft.	Present	1.1 mG	2.9 mG
	20 Years	1.5	4.2
100 ft.	Present	7.9	3.9
	20 Years	11.2	5.5

Source: Exh. HO-5

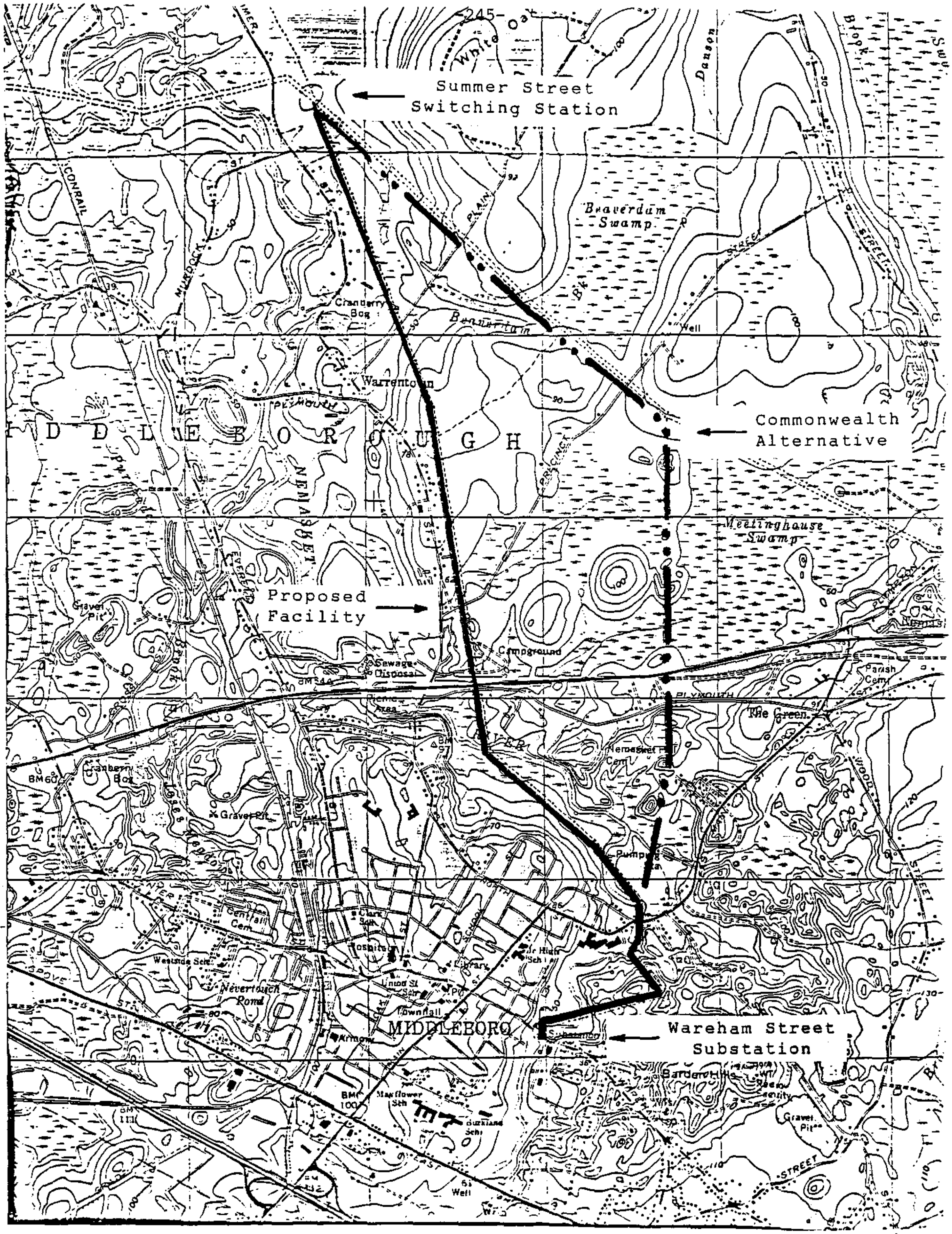

Figure 1

Proposed and Alternative Routes

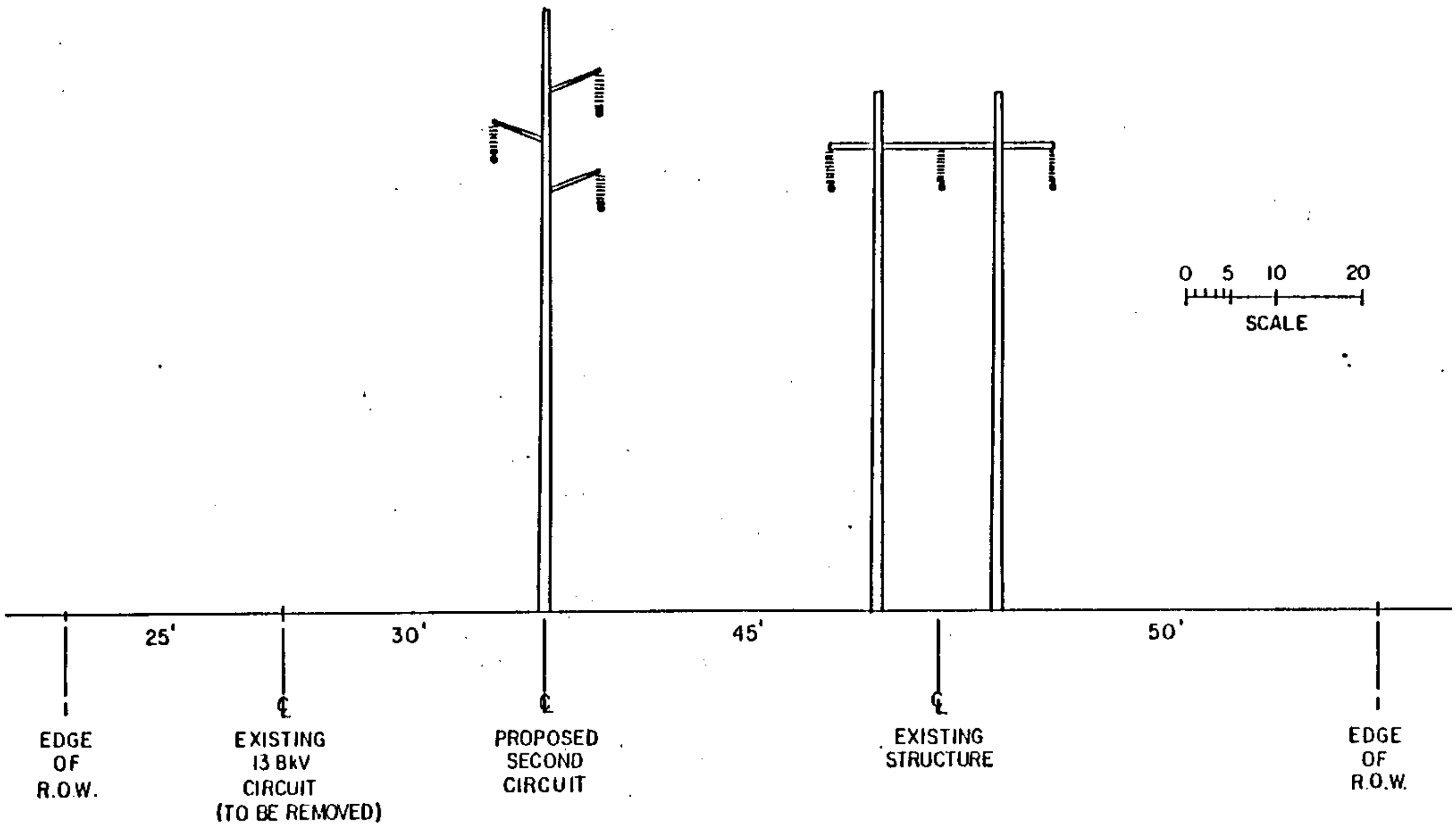

Figure 2

Proposed Typical ROW Section

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Commonwealth Electric Company for Approval of its Occasional Supplement to the 1984 Long-Range Forecast of Electric Requirements and Resources	)	EFSC 85-4A

FINAL DECISION

Frank P. Pozniak
Hearing Officer

On the Decision:

William S. Febiger

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Figures and Tables

The Energy Facilities Siting Council hereby CONDITIONALLY APPROVES the petition of the Commonwealth Electric Company to construct a 4.5-mile, 115 kilovolt transmission line from Harwich tap to Harwich substation included as part of Alternative 1 contained in the Occasional Supplement.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Commonwealth Electric Company ("Commonwealth" or "Company"), as well as the Cambridge Electric Company and the Canal Electric Company, are subsidiaries of the Commonwealth Energy System. Commonwealth produces, sells, and distributes electricity to approximately 233,000 customers in forty communities in Southern Massachusetts (Exh. C-1, p. 1). The Company's service territory is broken into three divisions: the Cape and Vineyard division ("Cape division");[1] the New Bedford division; and the Plymouth division (Exh. EFSC-1, IR 1.7). In 1985, Commonwealth had retail sales of 2,084,000 megawatt-hours, with a winter peak demand of 564 megawatts ("MW"). Commonwealth Electric Company, 15 DOMSC 125, 127 (1986).

In its review of the Company's most recent forecast filing, the Energy Facilities Siting Council ("Siting Council" or "EFSC") approved the Company's demand forecast and conditionally approved its supply plan.[2] Id. pp. 166-168.

The Company's proposed project is located in the Cape division,

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1/ The Cape division includes Cape Cod and Martha's Vineyard.

2/ Pursuant to G.L. c. 164, sec. 69I, a proposed facility must be consistent with a most recently approved long-range forecast or supplement thereto. While the Siting Council rejected the Company's 1984 supply plan in Commonwealth Electric Company, 12 DOMSC 39 (1985), the Siting Council approved the Company's forecast in Commonwealth Electric Company, 15 DOMSC 125 (1986). In this case, the Siting Council reviews the Company's proposed project to determine whether it is consistent with the Company's most recently approved forecast.

and consists of a proposed facility plan (or "proposal"), and alternative facility plans (or "alternatives"). In general, the proposed project consists of multiple elements to be constructed at intervals over a 30-year period, including improvements to the 115 kilovolt ("kV") transmission system, the bulk substation system, and the 23 kV distribution system (Exh. C-1; Exh. EFSC-1, Need Q. 7).[3]

The Company's proposal[4] consists of the construction of a new 115 kV transmission line of approximately 10 miles in length (Exh. C-1, p. 7). This line, known as the Harwich to Orleans transmission line ("HOTL"), would extend along new and expanded right-of-way approximately 175 to 210 feet wide, from the Company's existing Harwich substation in the Town of Harwich, through portions of the Towns of Harwich, Brewster, and Orleans, to the Company's existing Orleans substation in the Town of Orleans ("HOTL right of way" or "HOTL route"). (Exh. C-1, Appendix C-1; Tr. 5, pp. 115-116). The proposal also includes the construction of a 115kV/23kV substation on 13.9 acres of land owned by Commonwealth located off Route 137 (Chatham-Brewster Road) in Harwich ("Chatham substation") (Exh. C-1, p. 6). The Chatham substation is on the HOTL route, and would be connected to HOTL (Exh. C-1, Appendix C-1). In addition, the proposal consists of rebuilding an existing 4.5-mile, single-circuit 115 kV transmission line with larger conductors, but at the same voltage level (Exh. C-1, pp. 3, 6-7; Exh CAPE-4, Q.111, IR 3.9). This line, known as the Harwich tap-to-Harwich substation transmission line ("existing HT-H line"), extends on existing right of way from the Harwich substation to a point known as "Harwich tap" or "Dennis tap" ("HT-H right of way" or "HT-H route") The HT-H right of way is approximately 150 feet wide (Tr. 5, pp. 76-77). Moreover, the Company provided that the proposal would allow it to remove one of two existing 115 kV transmission lines (Exh. C-1, p. 5). These lines are

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3/ For a desription of the Company's proposed 23 kV system improvements, see Section I.C.1.a, <u>infra</u>.

4/ A more detailed description of the proposal is contained in Section III.B.1, <u>infra</u>.

known as the Dennis to Orleans transmission lines ("DOTL"), with the line that may be removed known as DOTL 1, and the line that would remain known as DOTL 2. Finally, the Company's proposal consists of upgrading the Wellfleet substation (Exh. C-1, pp. 3, 6-7).

The Company also identified two alternative facility plans, Alternative 1 and Alternative 2. See Section III.B.2, infra. Under Alternative 1, the Company would build a new 4.5-mile, 115 kV transmission line on the HT-H right of way ("second HT-H line") (Exhs. C-1, pp. 11-12, C-2, pp. 17, 69-72; Exh. CAPE-4, Q.111, IR 3.9). The Company also would rebuild DOTL 1 and the existing HT-H line with larger conductors, but at the same 115 kV level (Exh. C-1, pp. 3, 6-7, 11-12; Exh. C-2, pp. 17, 69-72). DOTL 1 extends on existing right of way from the Dennis tap to Orleans substation ("DOTL right of way" or "DOTL route"), and is 10 miles long (Exh. CAPE-4, Q.111, IR 3.9). The DOTL right of way is approximately 150 feet wide (Tr. 5, pp. 139-140). Finally, the Company would upgrade the Harwich and Wellfleet substations as part of Alternative 1 (Exh. C-1, pp. 11-12; Exh. EFSC-1, Need Q. 7).

Alternative 2 is similar to the proposal in that the Company would construct HOTL and rebuild the existing HT-H line with larger conductors at the same voltage voltage level (Exh. C-1, pp. 11-12; Exh. EFSC-1, Need Q. 7). However, unlike the proposal, the Company would not build the Chatham substation. The Company also would upgrade the Harwich and Wellfleet substations as part of Alternative 2 (Exh. C-1, pp. 11-12; Exh. EFSC-1, Need Q. 7).

At the request of intervenors and Siting Council staff, three additional alternative facility plans--the "Brewster substation alternative," the "double-end Orleans substation alternative," and the "underground/overhead alternative,"--were considered during the course of the proceeding.[5] See Section III.B.3, infra.

5/ The Siting Council notes that although these additional alternative facility plans were considered during the course of the proceeding, the Siting Council cannot approve the construction of any of the facilities contained in these plans in this proceeding as none of the alternatives were set forth in the Notices of Adjudication and Public Hearing.

B. Procedural History

On May 20, 1985, Commonwealth filed an Occasional Supplement to the 1984 Forecast of Commonwealth, Canal Electric Company, and Cambridge Electric Light Company requesting Siting Council approval to construct facilities in the Lower Cape (Exh. C-1). The Occasional Supplement set forth a description of proposed facility plan, as well as Alternatives 1 and 2.

On June 7, 1985, the Hearing Officer issued a Notice of Adjudication and Public Hearing on June 7, 1985 and directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2). A public hearing was held on July 18, 1985 in the Town of Harwich.

The Hearing Officer issued a second Notice of Adjudication and Public Hearing on December 18, 1986, and again directed the Company to publish and post the Notice in accordance with 980 CMR 1.03(2).[6] The Notice described the HOTL route and the Chatham substation under the proposal, and set forth a general description of Alternatives 1 and 2.

On January 27, 1987, a second public hearing was held in Harwich. In accordance with the direction of the Hearing Officer, the Company confirmed publication, posting and mailing of the Notice of Public Hearing and Adjudication.

Numerous petitions to intervene as a party and to participate as an interested person were received by the Hearing Officer. On August 23, 1985 and March 18, 1987, the Hearing Officer issued Procedural Orders granting all such petitions. Intervenors in the proceeding are: Barbara E. Armstrong, G. Rockwood and Cynthia Keith Clark ("Clarks"), Walter and Valerie Clark, Kenneth Felton, Steven E.

6/ This Notice reopened the proceeding for new petitions to intervene as a party or to participate as an interested person. A deadline of February 7, 1987 was set for filing such petitions. On February 6, 1987, the Hearing Officer issued a Procedural Order extending the period to intervene or participate from February 7 to February 20, 1987.

Grizey, John and Tekla Hines, Arthur and Agnes Howard, Richard J. Innis ("Innis"), William Marsh, Florence M. Ovaska ("Ovaska"), Arthur and Gertrude Rodenhaven, Sumner and Lila Tye, Alton E. Walker, David S. Wardwell, and a group of individual intervenors collectively known as the Citizens Against Powerline Encroachment ("CAPE").[7]

Finally, on March 18, 1987, the petition of Richard J. Doda to participate as an interested person was granted by the Hearing Officer.[8]

During the course of the proceeding, various motions were filed by CAPE and Innis. On August 23, 1985, CAPE filed a motion to dismiss the Occasional Supplement. In its motion, CAPE asserted that review of the Occasional Supplement could not commence until the Company filed a sensitivity analysis of the magnitude and timing of its planned additions and capacity needs under a reasonable range of contingencies, as ordered by the Siting Council in Commonwealth Electric Company, 12 DOMSC 39, 81 (1985). CAPE argued in its motion that the Siting Council's competence to review the Occasional Supplement was linked to this sensitivity analysis. On September 6, 1985, the Company filed a statement in opposition to the motion to dismiss. In a Procedural Order issued on September 9, 1985, the Hearing Officer denied the motion to dismiss on the basis that the Siting Council's competence to review the Occasional Supplement was

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7/ The members of CAPE were granted individual intervenor status by the Hearing Officer in a Procedural Order issued on August 23, 1985. On February 3, 1987, CAPE petitioned to amend its list of individual intervenors. In a Procedural Order issued on March 18, 1987, the Hearing Officer granted CAPE's petition. See Appendix A for list of CAPE members.

8/ In an August 23, 1985 Procedural Order and a September 13, 1985 letter order, the Hearing Officer granted the petition of Harold and Donna Kotzum to participate as interested persons. At that time, the Kotzums were also listed as CAPE members. On December 17, 1987, the Kotzums terminated their status as interested persons, and on April 14, 1987, legal counsel for CAPE informed the Hearing Officer that the Kotzums were no longer members of CAPE.

not linked to the filing of a sensitivity analysis.[9]

On May 15, 1987, CAPE filed a motion to compel Commonwealth to propose and identify one practical transmission alternative.[10] In its motion, CAPE requested a hearing date for oral argument and an opportunity to file a brief on this matter. The Hearing Officer granted this request (Tr. 1, p. 5; Tr. 5, pp. 4-5). In addition to presenting oral argument, CAPE and the Company filed initial and reply briefs on June 29 and July 6, 1987, respectively.[11]

On July 15, 1987, Innis filed a motion for a view requesting the Siting Council to view the segment of the HOTL route that would extend through Hawksnest State Park in Harwich and the neighborhoods which would be affected most directly in this area.[12] On August 3, 1987, the Company indicated that it did not oppose the motion. On August 4, 1987, the Hearing Officer issued a Procedural Order granting the motion. On August 14, 1987, the Siting Council staff viewed this area and other areas of the HOTL route, as well as alternative and existing 23 kV system routes and sites.[13]

9/ In Commonwealth Electric Company, 12 DOMSC 39, 81 (1985), the Siting Council ORDERED the Company to present the sensitivity analysis in its next forecast filing, and informed the Company that presentation of an acceptable sensitivity analysis will be a prerequisite to approval of future supply plans or of future applications to construct new generation or transmission facilities under the Siting Council's jurisdiction. The Company's subsequent forecast included a sensitivity analysis. In its review of that forecast, the Siting Council found that the Company had minimally complied with the ORDER contained in the 1985 decision. Commonwealth Electric Company, 15 DOMSC 125, 131, 157-158 (1986).

10/ For a discussion of this motion, see Section I.C.2, *infra*.

11/ These briefs will be referred to as CAPE Motion Brief, Company Motion Brief, CAPE Motion Reply Brief, and Company Motion Reply Brief. The Hearing Officer advised CAPE and the Company that a decision on CAPE's motion would be deferred until the Tentative Decision (Tr. 18, pp. 3-6). See Section I.C.2, *infra*.

12/ The neighborhoods referred to by Innis are in the area of Beach Plum Cirle and Quails Nest Run.

13/ Siting Council staff also viewed the HOTL route on July 18, 1985 and December 8, 1986.

Eighteen evidentiary hearings were held. The Company presented seven witnesses: W. Stephen Collings, environmental engineer; Harold W. Ecklund, chief electrical engineer; Robert L. Fratto, manager of the system development department; Karl Glosl, senior staff analyst; Beauford L. Hunt, Jr., supervisor of facility planning; Richard J. Morrison, senior attorney for Commonwealth; and Richard F. Withington, senior right of way agent. CAPE presented as witnesses Alexander Kusko, president of Alexander Kusko, Inc., consulting engineers, and five members of CAPE, Barbara Prindle-Eaton, Ronald Farris, Ada Litchfield, Carlota Viera Fonseca Pena, and Daniel Sylver. Innis presented one witness, Gilbert A. Bliss, director of forest and parks for the Massachusetts Department of Environment Management ("DEM").

The Hearing Officer offered 34 exhibits into the record. The Company presented 14 exhibits into the record. CAPE offered 19 exhibits and Innis presented 12 exhibits into the record.

Finally, CAPE filed briefs on October 26 and November 24, 1987. Innis filed his brief on October 26, 1987. The Company filed its briefs on November 17 and December 1, 1987.

C. Jurisdiction

1. Introduction

The Company's petition to construct HOTL and the Chatham substation under the proposal, HOTL under Alternative 2, and the second HT-H line under Alternative 1 is filed in accordance with G.L. c. 164, sec. 69H, which requires the Siting Council to ensure a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, and G.L. c. 164, sec. 69I, requiring electric companies to obtain Siting Council approval for construction of proposed or alternative facilities at a proposed or alternative site before a construction permit may be issued by any other state agency.

Construction of HOTL under the proposal and Alternative 2, and the second HT-H line under Alternative 1, fall squarely within the second definition of "facility" set forth in G.L. c. 164, sec. 69G:

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

At the same time, construction of the Chatham substation under the proposal falls within the third definition of "facility" set forth in G.L. c. 164, sec. 69G:

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

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility applications in three phases. First, the Siting Council requires the applicant to show that the facilities are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to present plans that satisfy the previously identified need and that are superior to alternative plans in terms of cost and environmental impact (see Section II.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to the alternate site in terms of cost, environmental impacts, and reliability of supply (see Section III, infra).

2. CAPE's Motion to Compel Commonwealth to Propose and Identify One Practical Transmission Alternative

a. Description

On May 15, 1987, CAPE filed a motion to compel Commonwealth to propose and identify one practical transmission alternative. In that motion, CAPE provided:

(1) Commonwealth is required by law and regulation (see particularly EFSC Administrative Bulletin 78-2) to provide in its Occasional Supplement at least one practical transmission alternative to its proposal.

> (2) Commonwealth has failed to meet said requirement. It has repeatedly written that no matter which transmission alternative is selected, a new right of way on its proposed route (HOTL route) will be purchased or taken by eminent domain, and cleared. For its proposal, such a right of way would hold both a 115 kV line and a 23 kV line. For all other proposals [alternatives], the right of way would hold a 23 kV line. In other words, no matter which alternative is selected, the CAPE citizens must accept a wide, cleared right of way and substantial power line towers and conductors across or very near their properties. The alternatives set forth, then, are not practical within the meaning of the regulation.

Under its proposal, as well as Alternatives 1 and 2, the Company would construct a new 795 aluminum conductor steel-reinforced ("ACSR"), 23 kV distribution line in two stages along the HOTL route, in order to supply distribution circuits and strengthen back-up capabilities between Harwich, Orleans, and the proposed Chatham substations ("23 kV tie line") (Exh. C-1, p. 28, Appendix C-1; Exhs. EFSC-8, EFSC-12; Tr. 5, pp. 127-130; Tr. 14, pp. 109-110). In addition, the Company would construct new or upgraded on-street 23 kV feeder lines to better supply distribution circuits in Harwich, Chatham, and Brewster from the proposed Chatham substation ("23 kV feeder line improvements") (Exh. C-1, p. 28, Appendix C-1; Exhs. EFSC-8, EFSC-12; Tr. 5, pp. 127-130). In conjunction with the 23 kV feeder line improvements, the Company expects to remove 5.7 miles of older 1/0 copper conductors located on a separate right of way ("1/0 line"), which currently feeds sections of Harwich and Chatham from Harwich and Orleans substations (Exhs. EFSC-8, EFSC-9, EFSC-12).

The 23 kV tie line initially would extend approximately eight miles along the HOTL right of way from Orleans substation to Pleasant Lake Avenue in Harwich, from where it would connect via on-street 477 ACSR conductors to Harwich substation (Exhs. EFSC-8, EFSC-10). When warranted by load growth, the 23 kV tie line would be extended with 795 ACSR conductors along the remainder of the HOTL right of way to Harwich substation (Exh. C-1, Appendix C-1).

CAPE requested that briefs be filed on its motion. The Hearing Officer granted this request, and required that the briefs address each of three issues: (1) to interpret "other site locations" as that term is used in G.L. c. 164, sec. 69I(3); (2) to define "practical alternative" as that term is used in Administrative Bulletin 78-2, and to indicate whether the alternatives provided by the Company are practical alternatives as defined; and (3) to address whether Siting Council jurisdiction over the 23 kV tie line is relevant to the proceeding, and, if it is, then address the third definition of facility contained in G.L. c. 164, sec. 69G,[14] and the Siting Council's final advisory opinion in Eastern Utilities Associates, 12 DOMSC 267 (1983) (Tr. 5, pp. 4-5).

CAPE and the Company filed briefs addressing these issues. The Siting Council's review of this matter focuses on whether the Siting Council has jurisdiction over the 23 kV tie line.

b. Analysis

The definitions of facility contained in G.L. c. 164, sec. 69G provide the thresholds for Siting Council jurisdiction over facility proposals. The second and third definitions of facility are pertinent to this analysis. The relevant part of the second definition provides that a facility is "any new electric transmission line having a design rating of sixty-nine kilovolts or more." The third definition provides that a facility is "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."

Clearly, the 23 kV tie line does not fall within the second definition of facility. Thus, the Siting Council must determine whether the 23 kV tie line is an ancillary structure which is an integrated part of jurisdictional facilities.

As an initial matter, the Company argues that G.L. c. 164, sec.

14/ The term "facility," as set forth in G.L. c. 164, sec. 69G, comprises five definitions. The third definition provides that a facility is "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."

69G makes a clear distinction between "transmission lines" and "structures" in the second and third definitions of facility, and therefore a "transmission line,"--such as the 23 kV tie line--is not a "structure" as that term is used in Section 69G (Company Motion Brief, pp. 15-16, 20-21). Thus, Commonwealth argues that the Siting Council's jurisdiction is explicitly limited to transmission lines which constitute facilities--transmission lines of 69 kV or greater capacity and one mile or more in length (id., pp. 13-15).

The Siting Council rejects the Company's interpretation of Section 69G. Neither G.L. c. 164, sec. 69G, nor any other relevant sections of the Siting Council's enabling statute, contain any language that distinguishes "transmission lines" from "structures." In addition, commonplace dictionary definitions of "structures" lead us to conclude that transmission lines are in fact "structures." Further, in Northeast Energy Associates, 16 DOMSC 335, 343, 384 (1987), the Siting Council considered a 345 kV transmission line of less than one mile in length connected to a jurisdictional generating unit, to be an ancillary structure. Accordingly, the Siting Council finds that a transmission line may be considered an ancillary structure for the purposes of G.L. c. 164, sec. 69G.

In essence, the critical question here is whether the 23 kV tie line is (1) ancillary and (2) an integrated part of the operation of a jurisdictional facility. CAPE maintains that the 23 kV tie line, the primary 23 kV line coming out of the proposed Chatham substation, should be considered ancillary to HOTL (Cape Motion Brief, p. 4; CAPE Brief, pp. 7-8). Defining ancillary as "subordinate, subsidiary, auxiliary, supplementary," CAPE argues that, applying this functional approach, the 23 kV tie line must be considered ancillary to HOTL and the Chatham substation, for without the 23 kV tie line, HOTL and the Chatham substation are useless (id.). CAPE further argues that application of this functional approach also mandates classification of the 23 kV tie line as an "integrated part of the operation" of HOTL (id.). CAPE maintains that the record demonstrates that the 23 kV tie line is an integrated part of HOTL and the Chatham substation (CAPE Motion Brief, p. 5).

The Company argues that the 23 kV tie line and the 23 kV feeder line improvements are necessary regardless of whether the proposal or any of the alternatives are approved by the Siting Council (Company Motion Brief, p. 16; Company Motion Reply Brief, p. 2). The Company maintains that there is a separate and distinct need for the 23 kV tie line, and therefore, this line is not an ancillary and integrated part of the operation of HOTL (Company Motion Brief, p. 16). Finally, asserting that integral relation implies that one entity cannot exist without the other, the Company argues that if the proposal and alternatives are not necessary for the operation of the 23 kV tie line, then it cannot be said that the lines are integrally related (id.).

The Siting Council considered whether a structure was a facility in Eastern Utilities Associates, 12 DOMSC 267 (1983). In that case, the Siting Council determined that a substation was a facility on the basis that it was ancillary to and integrated with a jurisdictional 115 kV transmission line. Id., pp. 270-271. However, in that case, the Siting Council did not set forth a standard for determining whether a structure is ancillary or an integrated part of the operation of a jurisdictional facility. In this case, the Siting Council sets forth a standard for determining when a 23 kV tie line, or any other structure, falls within the statutory definition of facility.

The Siting Council hereby establishes a two-part standard for determining whether a structure is a facility. A structure is a facility under G.L. c. 164, sec. 69G if (1) the structure is subordinate or supplementary to a jurisdictional facility, and (2) the structure provides no benefit outside of its relationship to the jurisdictional facility.

The record in this proceeding demonstrates that, while the 23 kV tie line is subordinate or supplementary to the proposed and alternative jurisdictional facilities, the 23 kV tie line does provide a benefit to the supply system, even without construction of the proposed or alternative jurisdictional facilities. The Company provided that the existing 23 kV feeder lines are inadequate to support the growing load in the Lower Cape as their thermal rating are being exceeded (Exh. EFSC-2, Q.33; Exh. CAPE-3, IR 2.14; Exh. C-2, pp.

22, 66). Given the Company's existing supply system, the Company's distribution lines would be overloaded in the event of the contingency of an outage of the Orleans substation (see Sections II.A.3.c.1. and II.B.2.b, infra).

In that the 23 kV tie line provides a benefit outside of its relationship with the jurisdictional facilities, the Siting Council finds that the 23 kV tie line does not fall within the third definition of facility contained in G.L. c. 164, sec. 69G.[15] Accordingly, CAPE's motion to compel Commonwealth to propose and identify one practical transmission alternative is denied. The Siting Council further finds that the Company is not required to file an alternative that does not utilize the HOTL right of way in order to demonstrate that it presented a reasonable range of practical facility siting alternatives.[16]

In finding that the 23 kV tie line is not jurisdictional, the Siting Council does not support or endorse the use of the HOTL right of way for the 23 kV tie line. In previous decisions, the Siting Council has found that the use of an existing right of way as the site of new transmission lines is the most appropriate way to achieve the proper statutory balance between need, cost, and environmental impact. Massachusetts Electric Company, 13 DOMSC 119, 191-192 (1985); Boston Edison Company, 3 DOMSC 44, 53-55, 61-64 (1978). In light of

15/ Similarly, the proposed upgrade of the Harwich substation under Alternatives 1 and 2, as well as the proposed upgrade of the Wellfleet substation under the proposal and Alternatives 1 and 2, would not be considered facilities under the third definition of facility as they provide benefits to the system irrespective of the jurisdictional facilities. However, the proposed Chatham substation is considered a facility because it provides no benefit to the system without HOTL. Finally, the rebuilding of DOTL 1 and the existing HT-H line are expressly excluded from the second definition of facility contained in G.L. c. 164, sec. 69G, and therefore are not considered facilities.

16/ We note that the Company's 23 kV tie line and 23 kV feeder line improvements are considered in our review of alternate approaches to the proposed project. See Section II.B.2.e, infra.

the cost and environmental impacts that would be incurred (see Section III.D and E, infra), the use of the HOTL right of way for a 23 kV distribution line seems wholly inappropriate. In fact, the Company provided that it could make necessary 23 kV improvements along town and state roads, or along the 1/0 line provided that its easement rights for the 1/0 line right of way do not prohibit such improvements (Tr. 13, pp. 88-90; Tr. 14, pp. 104-105). Therefore, the Siting Council encourages the Company to investigate other routes for its 23 kV tie line.

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

In carrying out this statutory mandate with respect to proposed energy facilities in the Commonwealth, the Siting Council evaluates whether there is a need for additional energy resources[17] to meet reliability or economic efficiency objectives. The Siting Council therefore must find that additional energy resources are needed as a prerequisite to approving proposed energy facilities.

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated 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 Council 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. Northeast Energy Associates, 16 DOMSC 327, pp. 334-360 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); Boston Edison Company, 2 DOMSC 58, 62 (1977); New England Electric System, 2 DOMSC 1, 9 (1977); Eastern Utilities Associates, 1 DOMSC 312, 313 (1977). With regard to contingencies, the Siting Council has

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

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. Nantucket Electric Company, 15 DOMSC 363, 380-383 (1987); Massachusetts Electric Company, 13 DOMSC 119, 137 (1985); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Eastern Utilities Associates, 10 DOMSC 71, 76-78 (1983); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Boston Edison Company, 3 DOMSC 153, 156-162 (1980); Boston Edison Company, 2 DOMSC 58, 60-62 (1977); Eastern Utilities Associates, 1 DOMSC 312, 316-318 (1977); Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 101 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, 13 DOMSC 119, 178-179, 183, 187, 246-247 (1985).

2. Description of the Existing System

Commonwealth's existing system in the Cape division consists of a generating station, and 115 kV transmission and 23 kV distribution systems.

The Canal generating station, a principal base load plant serving the Commonwealth system, is located just inside the Cape division at the north end of the Cape Cod Canal. With the exception of some peak load generating units on Martha's Vineyard, however, Commonwealth owns no additional generating capacity in the Cape division (Exh. EFSC-1, IR 1.1).

The Cape division is served by a 115 kV transmission system and a 23 kV distribution system. The existing 115 kV transmission system is shown in Figure 1, and the current 23 kV distribution system is shown in Figure 2.

Figure 1

EXISTING 115 KV TRANSMISSION SYSTEM

1 . . . BARNSTABLE 115KV SWITCHING STA.
2 . . . BOURNE 115KV SWITCHING STA.
3 . . . FALMOUTH 115KV SUB.
4 . . . HARWICH 115 KV SUB.
5 . . . HATCHVILLE 115 KV SUB.
6 . . . HYANNIS JUNCTION 115 KV SUB
7 . . . MASHPEE 115 KV SUB.
8 . . . ORLEANS 115 KV SUB.
9 . . . OTIS 115 KV SUB.
10 . . . SANDWICH 115 KV SUB.
11 . . . WELLFLEET 115 KV SUB.

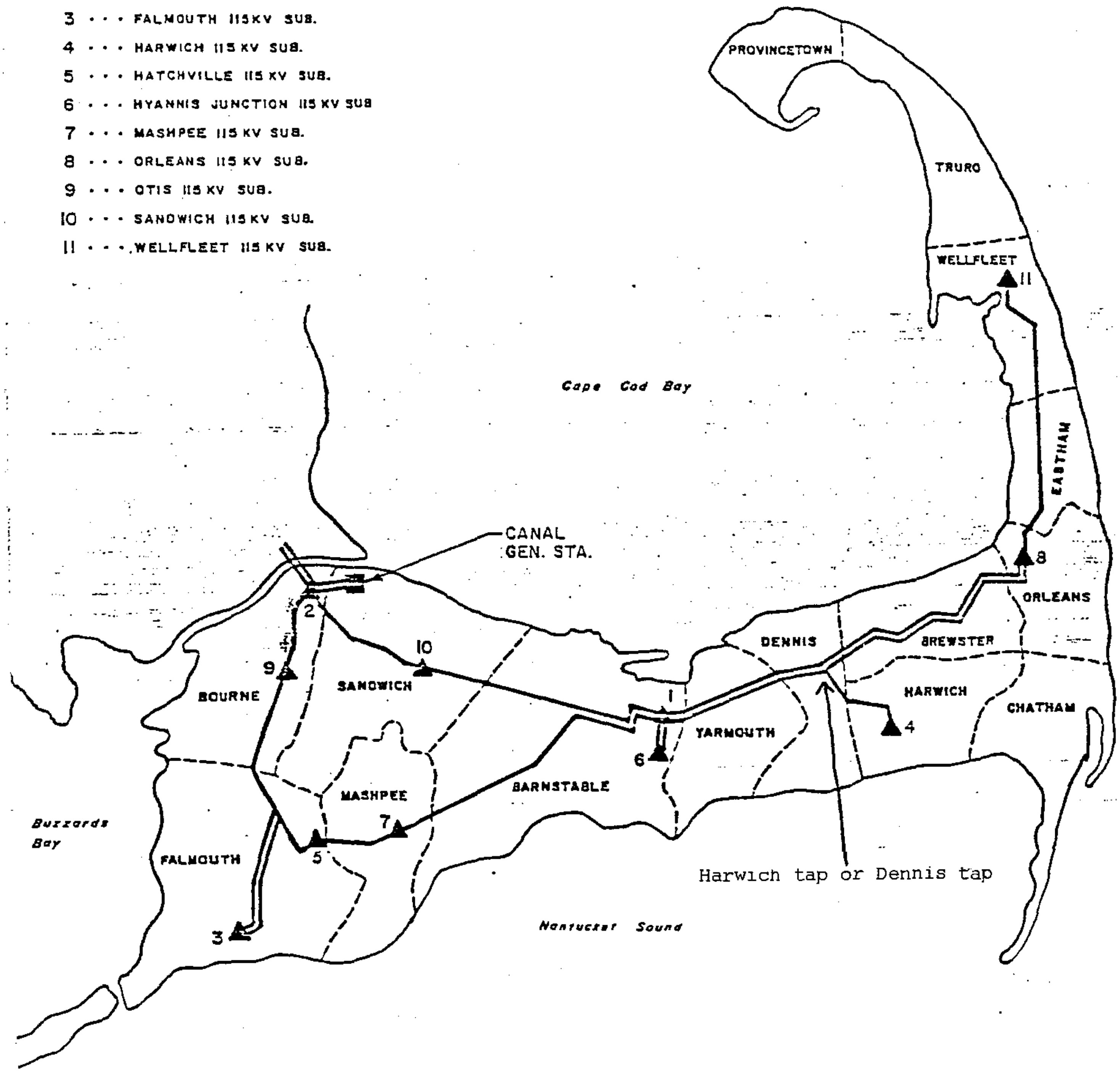
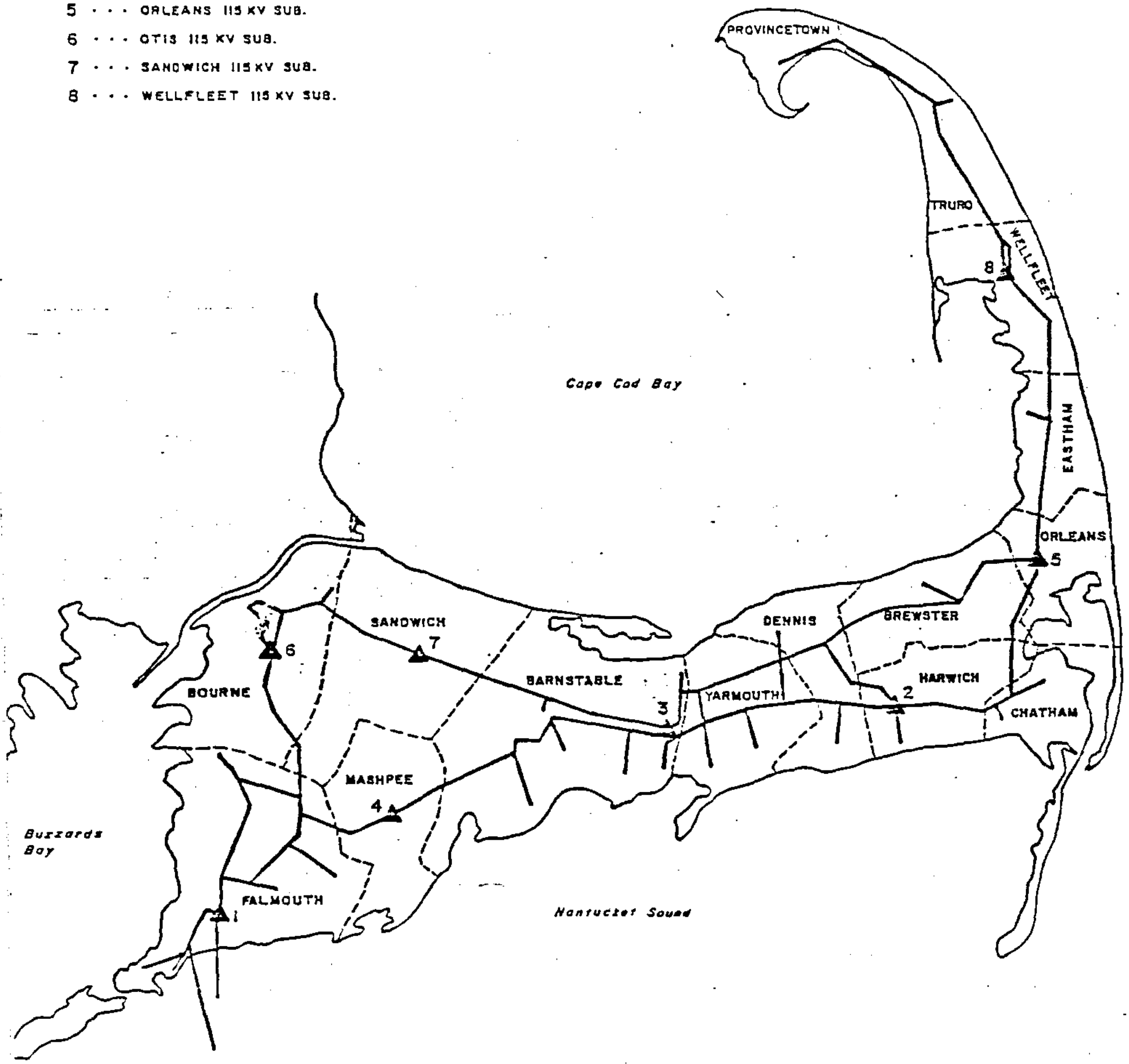


Figure 2

EXISTING 23 KV DISTRIBUTION SYSTEM

1 . . . FALMOUTH 115 KV SUB.
2 . . . HARWICH 115 KV SUB.
3 . . . HYANNIS JUNCTION 115 KV SUB.
4 . . . MASHPEE 115 KV SUB.
5 . . . ORLEANS 115 KV SUB.
6 . . . OTIS 115 KV SUB.
7 . . . SANDWICH 115 KV SUB.
8 . . . WELLFLEET 115 KV SUB.



The proposed project affects service to an area that includes generally the Towns of Harwich, Chatham, Brewster, Orleans, Eastham, Wellfleet, Truro, and Provincetown ("Lower Cape"). As shown in Figure 1, two 115 kV circuits run eastward from the Barnstable switching station, near Hyannis Junction substation, and extend through Yarmouth to a point in Dennis, known both as "Harwich tap" and "Dennis tap." From this common tap point, three circuits extend radially in two different directions to serve the Lower Cape towns.

One single-circuit 115 kV radial line, the existing HT-H line, extends southeastward from Harwich tap 4.5 miles to Harwich substation. The existing HT-H line is a 4/0 ACSR circuit on H-frame structures put in service in 1958, with a rated normal capacity of 31 megavar-amperes ("MVA") (Exh. EFSC-4, Need Q.38; Exh. CAPE-2, Q.14; Tr. 8, p. 76). The Harwich substation is double-ended, consisting of a recently upgraded General Electric 50 MVA transformer bank ("Harwich GE transformer") and an Allis Chalmers 25 MVA transformer bank ("Harwich A-C transformer") (Exh. CAPE-2, Q.14; Tr. 8, pp. 9-10). The Harwich A-C transformer serves load in the area extending generally eastward from Harwich substation toward Chatham and Orleans, while the Harwich GE transformer serves load in the area extending generally westward from Harwich substation toward Hyannis (Exh. C-2, p. 65).

Two circuits also continue eastward from Dennis tap as a double radial line, extending approximately ten miles through Brewster to Orleans substation. This ten-mile segment includes DOTL 1, which is a 4/0 ACSR circuit on H-frame structures placed in service in 1949, and DOTL 2, which is a 795 ACSR circuit on single-pole davit-arm structures placed in service in 1982 (Exh. C-1, p. 1; Exh. CAPE-7, Q. 118).[18] Like the existing HT-H line, DOTL 1 has a capacity of 31 MVA (Exh. CAPE-2, Q. 14); DOTL 2 has a capacity of about 150 MVA (id.; Exh. C-1, p. 9). The Orleans substation consists of a single 33 MVA

18/ Construction of DOTL 2 was approved by the Siting Council in Commonwealth Electric Company, 6 DOMSC 33 (1981). In that decision, Commonwealth provided that it was developing plans for HOTL. Id., pp. 43, 57. Further, the Company provided that DOTL 1 would be removed if HOTL was approved and constructed. Id., p. 41.

transformer bank (Exh. CAPE-2, Q.14).

From Orleans substation, a single 115 kV circuit continues northward, terminating at Wellfleet substation. Wellfleet substation is double-ended, consisting of a General Electric 20 MVA transformer bank ("Wellfleet GE transformer") and a Moloney 26 MVA transformer bank ("Wellfleet Moloney transformer") (Exh. CAPE-2, Q.14). The Wellfleet GE transformer serves load in the area extending generally southward from Wellfleet substation toward Orleans (Exh. C-2, p. 67).

The 23 kV distribution system includes a set of 795 ACSR conductors that generally extends along the same rights of way as the above-described 115 kV system, interconnecting Hyannis Junction, Harwich, Orleans and Wellfleet substations via Harwich tap/Dennis tap (Exh. C-2, p. 64; Exh. EFSC-9). Additional 23 kV lines provide a southern loop extending directly from Hyannis Junction substation to Harwich substation, and then from Harwich substation to Orleans substation via South Chatham (id.). While considerable portions of this southern loop have been upgraded to 477 or 795 ACSR, a 9.8-mile section of the loop, beginning 1.5 miles east of Harwich substation and extending to the DOTL right of way just south of Orleans substation, consists of the 1/0 line (id.).

3. Reliability of Supply

a. The Company's Methodology

The Company analyzed the need for the proposed project on the basis of the results of load flow studies of the transmission and distribution system in the Lower Cape under outage contingencies, including estimates of power flow on major elements of the system and related voltage levels on distribution feeder lines and circuits. Commonwealth presented load flow studies relating to (1) the ability of the transmission network to maintain service to 115/23 kV bulk substations, and (2) the ability of the bulk substation and distribution system to adequately serve the area load (Exh. C-2, pp. 64-67, 73-81; Exh. CAPE-3, IR 2.14).

The Company based its load flow analyses on forecasted summer peak loads for the system in the short run, including the years 1986-1990 (Exh. C-2, pp. 7-9, 59, 61, 64-67; Exh. EFSC-1, Load Projections Q.2, IR 1.2). Using regression analysis, the Company adjusted the summer and winter system peak loads to reflect the non-coincident divisional peak loads, and then allocated the divisional loads to the bulk substation level (Exh. EFSC-1, Load Projections Q.3, Q.4, and Q.10, IR 1.5-1.7).

The Company developed its load flow studies based on summer peak loads that are consistent with the most recent forecast approved by the Siting Council in Commonwealth Electric Company, 15 DOMSC 125, 131 (1986) (Exh. EFSC-1, Load Projections Q.2, IR 1.2-1.4). Table 1 shows the non-coincident summer peak loads forecasted for the Lower Cape substations and the Cape division.[19]

Table 1
Forecasted Summer Peak Load
Lower Cape Substations and Cape Division (MW)

Substation	1986	1990	1995	1999
Harwich GE	25.6	28.8	31.3	33.0
Harwich A-C	23.2	25.9	28.0	29.5
Orleans	21.9	24.6	26.7	28.2
Wellfleet GE	7.1	8.3	9.2	9.8
Wellfleet Moloney	17.9	20.8	23.0	24.6
Cape Division (Total)	271	307	366	355

Source: Exh. EFSC-18.

19/ The Company later provided bandwidth projections of system peak loads developed as part of the Company's most recent forecast filing, not yet reviewed by the Siting Council, again adjusted to reflect divisional peak loads and allocated to the bulk substation level (Exh. EFSC-18) (see Section III.F.2, infra).

The Company provided available records of transmission and distribution outages affecting the Lower Cape (Exhs. EFSC-22A, EFSC-22B, EFSC-22C, EFSC-22D).[20] The Company noted that, for the most part, available records are limited to outages that actually resulted in interruptions of service to 200 or more customers, and therefore information on facility outages that were adequately backed up by other elements of the transmission and distribution system generally is not available (Tr. 10, p. 6).

The Company also addressed specific reliability criteria for its transmission and distribution system, relating to the need for back-up supplies, minimum voltage levels, and limits on equipment loading. As its basic reliability criteria, the Company proposed that (1) all reliability studies relating to future system modifications should be based on peak load conditions, (2) voltage levels should not drop below 0.95 per unit on the 23 kV distribution lines, (3) bulk substation transformers should not exceed their normal overload capabilities, and (4) transmission and distribution lines should not exceed their designated ratings for normal and emergency conditions (Exh. EFSC-1, Need Q.7).

In its load flow studies, the Company was consistent in relating its assumptions and conclusions to the basic criteria it had recognized. The Siting Council finds that the Company's future load assumptions and reliability criteria are acceptable, and that the Company used reviewable and appropriate methods for assessing system reliability based on load flow analysis.

20/ Commonwealth could not provide evidence, within its system, of a simultaneous loss of two or more high voltage transmission lines on a common right of way caused by a single localized incident along the same right of way (Exh. CAPE-7, Q.126). However, the Company reported that such losses had occurred in a neighboring New England utility system (*id.*). During the proceeding, CAPE's witness, Alexander Kusko, provided testimony relating to transmission outage frequency (see Section III.F.1, *infra*).

b. Reliability of the Existing Transmission System

i. DOTL 1

The Company noted that the availability of back-up transmission to Orleans and Wellfleet Substations depends on DOTL 1--a 37-year old transmission line (Exh. C-1, p. 1). The Company raised both reliability and economic concerns related to continued operation of DOTL 1, and has taken the position that DOTL 1 has exceeded its useful life and should be removed in order to eliminate the cost of further maintaining the line (Exh. C-1, pp. 1, 5, 9; Exh. C-2, p. 16; Exh. EFSC-1, Need Q. 9).[21] In fact, Commonwealth provided that the proposal will allow it to remove DOTL 1 (Exh. C-1, p. 5).

Commonwealth provided updated analyses relating to the need for 115 kV system improvements to back up DOTL 2. First, the Company provided maps and load flow analyses showing that significant portions of the Lower Cape service area would lose power under the contingency of an outage of DOTL 2, assuming loads of 40 to 100 percent of 1986 summer peak load and the absence or unavailability of DOTL 1 (Exh. C-2, pp. 73-80). Second, the Company provided records and summary information concerning the extent of past maintenance and repairs for DOTL 1 (Exh. EFSC-1, Need Q.9, IR 1.10).

Based on the age and condition of DOTL 1, it is possible that DOTL 1 may provide less reliable back-up than a newer or upgraded transmission line. First, to the extent that DOTL 1 must be scheduled for repairs more often than a newer line, there is a greater probability that, in the event that an unscheduled outage of DOTL 2 occurs, DOTL 1 already would be out of service. Second, to the extent

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21/ In Commonwealth Electric Company, 6 DOMSC 33, 44, 47, 56 (1981), the Siting Council approved construction of DOTL 2 based principally on the need for a redundant or back-up transmission line. In that decision, the Siting Council noted that increased maintenance and repair costs could result from continued operation of DOTL 1, and that the Company had concerns as to the integrity of the line under severe wind and snow conditions. Id., pp. 45-46.

that DOTL 1 is more vulnerable to severe wind or snow conditions, there is a greater probability that, in the event DOTL 2 experiences an unscheduled outage during such conditions, DOTL 1 would experience a simultaneous unscheduled outage.

Even when DOTL 1 is available to provide back-up transmission for DOTL 2, the forecasted peak loads at Orleans and Wellfleet substations (see Table 1) significantly exceed the 31 MVA rated capacity of DOTL 1. Thus, if DOTL 2 is unavailable under peak load conditions, even when DOTL 1 is available, support would need to be provided from Harwich substation in order to back up the other Lower Cape substations.

Therefore, the Siting Council finds that the Company has demonstrated that DOTL 1 is unreliable (1) because of its age and condition, and (2) in the event of an outage of DOTL 2.

ii. Existing HT-H Line

The existing HT-H line is 29 years old, just short of its 30-35 year expected life (Exh. C-2, p. 47). An outage on this line would result in the loss of both the A-C and GE transformers at Harwich substation (Exh. EFSC-1, Need Q.2).[22] The Company stated that, under peak and near-peak load levels forecasted for Summer 1987, the load normally served by the Harwich substation could not be supported reliably by neighboring Hyannis Junction and Orleans substations (Exh. C-2, pp. 19, 81). Even with the existing HT-H line in service, the Company stated that the line's normal capacity of 31 MVA currently is exceeded 60 to 80 percent of the time during the summer (Tr. 8, p. 42). Thus, the Company provided that upgraded transmission capacity is needed to serve Harwich substation adequately even under normal conditions (id., pp. 42-43).

22/ The Company provided that three outages in the last ten years, resulting in loss of service to customers in the Harwich area, probably were located on the existing HT-H line (Tr. 14, pp. 123-136).

The Company provided that under normal operating conditions, area load probably could be met for a number of years with limited power flow through Harwich substation and partial support of the area by neighboring substations (Tr. 8, pp. 45-47). However, under the contingency of an outage of the existing HT-H line, the Company's load flow study indicates that voltage levels in parts of Chatham could barely be supported by Orleans and Hyannis Junction substations at 80 percent of the forecasted peak load in Summer 1987 (Exh. C-2, p. 81).

Thus, based on the record, the Siting Council finds that the Company has demonstrated that the existing HT-H line is unreliable because (1) of its age, and (2) the neighboring substations and the existing distribution system are not able to adequately support a loss of both Harwich substation transformers.

c. Reliability of Existing Distribution System

The Company provided that, in the event of a transformer outage at either the Orleans or Harwich substations, existing distribution lines and equipment in the Lower Cape would become overloaded (Exh. C-2, p. 2). The Company addressed in detail outage contingencies at two transformers--the Orleans substation and the Harwich A-C transformer. Based on the most recently approved forecast, the Company presented load flow diagrams of each contingency for 1986 (Exh. C-2, pp. 65, 67). The Company also presented comparisons of equipment loadings and capacities for all years between 1986 and 1990 (id., pp. 64, 66).

i. Orleans Substation Outage

The Company stated that, in the event of an outage of Orleans substation, overloading of both the Harwich A-C transformer and certain feeder line equipment could be expected under peak load conditions by Summer 1986 (id., p. 66). The Company determined that, under such a contingency, power flow through the Harwich A-C transformer would be 36.5 MVA in 1986, exceeding the summer emergency rating by 3.7 percent (id.). At the same time, the Company stated that a section of the 1/0 line extending from Pleasant Lake Avenue, in Harwich, to South Chatham would be overloaded by 15 percent (id.).

The Company presented a load flow diagram for the 1986 Orleans substation outage contingency indicating that, under peak summer load, voltages would drop to as low as .908 per unit in Chatham and .907 per unit in Brewster without load shedding (id., p. 67). The Company stated that, under this contingency, it would shed approximately 6.8 MW of load on a rotating basis in order to maintain minimum acceptable voltage of .95 per unit (Exh. CAPE-3, Q.61).

Thus, based on the Company's peak load contingency analysis, the minimum voltage levels in Chatham and Brewster and the overloading of the 1/0 line between Harwich and Chatham already violate the Company's reliability criteria by a significant margin (see Section II.A.3.a, supra). The overloading of the 1/0 line indicates that the 23 kV system serving Chatham is significantly undersized for its present function.

The Company's contingency analysis also shows that under summer peak load, the capacity of the Harwich A-C transformer would be exceeded slightly as of 1986.[23] This analysis indicates that the power flow that would be required from the Harwich A-C transformer to support an Orleans substation outage would increase from 36.5 MVA in

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23/ The Company presented no evidence indicating whether it had considered whether support from the Harwich GE transformer or the Hyannis Junction substation, in addition to the Harwich A-C transformer, could help meet the contingency of an Orleans substation outage. The capacity of the Harwich GE transformer has been expanded from a 20 MVA bank to a 50 MVA bank since the Company prepared and filed its load flow studies of the existing system (Tr. 8, pp. 9-10). In addition, updated information provided by the Company shows that a new 23 kV line has been built along the DOTL right of way between Dennis tap and Brewster, not shown in the Company's petition or prefiled testimony (Exhs. EFSC-9, EFSC-10). It is unclear whether the existing 23 kV system,--currently or with minor modifications--could allow the Harwich GE transformer and/or Hyannis Junction substation to help support an Orleans substation outage. With respect to the Harwich GE transformer, it should be noted that existing constraints of the existing HT-H line, if assumed, could inhibit the ability of Harwich substation to safely support load up to the maximum capacity of both transformers (Exh. CAPE-2, Q.14).

1986 to 42.1 MVA in 1990, unless partially supported by more distant transformers (Exh. C-2, p. 66). Considering the additional increases in overall Lower Cape substation loadings forecasted beyond 1990 (see Table 1), the Harwich A-C transformer may need to provide levels of support well above its safe capacity within the ten-year forecast period in order to meet the contingency of an Orleans substation outage under summer peak load.

Based on the record, the Siting Council finds that the Company has demonstrated that the existing distribution system and the Harwich A-C transformer are unreliable for supporting an outage of Orleans substation under summer peak load.

ii. Harwich A-C Transformer Outage

The Company stated that, in the event of an outage of the Harwich A-C transformer, overloading of certain feeder and main breaker equipment at the Hyannis Junction substation, and overloading of main breaker equipment at the Harwich GE transformer, could be expected under peak conditions by Summer 1986 (Exh. C-2, p. 64). An overload of the Harwich GE transformer itself, which the Company had identified as a reliability problem based on the originally filed load flow study assumptions, would be avoided as a result of the Company's recent upgrading of that transformer from a 20 MVA bank to a 50 MVA bank (Exh. C-2, p. 64; Tr. 8, pp. 9-10).

The Company presented a load flow diagram indicating that under Summer 1986 peak load, voltages would drop to as low as .948 per unit in Chatham (Exh. C-2, p. 65). Thus, the Company's peak load contingency analysis demonstrates that the low voltage levels in Chatham violate the Company's reliability criteria (see Section II.A.3.a, supra).

The Siting Council finds that the Company has demonstrated that the existing distribution system generally, and certain breaker equipment at Lower Cape substations in particular, are unreliable for supporting an outage of the Harwich A-C transformer under summer peak load.

d. Conclusions on Reliability of Supply

The Siting Council has found that the Company's future load assumptions and reliability criteria are acceptable, and that the Company used reviewable and appropriate methods for assessing system reliability based on load flow analysis.

With respect to the reliability of the existing transmission system in the Lower Cape, the Siting Council has found that the Company has demonstrated that DOTL 1 is unreliable (1) because of its age and condition, and (2) in the event of an outage of DOTL 2. The Siting Council also has found that the Company has demonstrated that the existing HT-H line is unreliable because (1) of its age, and (2) the neighboring substations and the existing distribution system are not able to adequately support a loss of both Harwich substation transformers.

With respect to the reliability of the distribution system in the Lower Cape, the Siting Council has found that the Company has demonstrated that the existing distribution system and the Harwich A-C transformer are unreliable for supporting an outage of Orleans substation under summer peak load. The Siting Council also has found that the Company has demonstrated that the existing distribution system generally, and certain breaker equipment at Lower Cape substations in particular, are unreliable for supporting an outage of the Harwich A-C transformer under summer peak load.

Based on the foregoing, the Siting Council finds that the Company has demonstrated that its existing supply system is inadequate to satisfy existing and expected loads in the Lower Cape with acceptable reliability. Accordingly, the Siting Council finds that the Company has established that additional energy resources are needed in the Lower Cape.

B. Comparison of the Proposed Project and Alternate Approaches

1. Standard of Review

G.L. c. 164, sec. 69H requires the Siting Council 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 lowest possible cost. In addition, G.L. c. 164, sec. 69I requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[24]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternate approaches in terms of cost, environmental impact, and ability to meet the previously identified need. Northeast Energy Associates, EFSC 87-100, pp. 23-43 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 212-218 (1986); Massachusetts Electric Company, 13 DOMSC 119, 141-183 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 73-74 (1985).

2. Project Approaches to the Identified Need

As its preferred project approach to meeting the identified need, the Company has proposed to construct improvements to the transmission and distribution system in the Lower Cape in order to improve system reliability and reduce line losses (Exh. C-1, p. 5). In its filing, the Company also considered three alternate approaches to the proposed project--(1) the "no-build" approach; (2) increased conservation and load management ("C&LM"); and (3) new generating capacity (Exh. C-1, p. 11). During the course of the proceeding, the Company also identified a set of low-voltage (23 kV) system improvements, which the Company considered to be a part of its proposed project (see Section I.C.2.a, supra). In that these 23 kV system improvements were analyzed in some detail and constitute a discrete project element, the

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24/ G.L. c. 164, sec. 69I also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the Company's proposed site, as well as other site locations, in Section III, infra.

Siting Council also considers the Company's proposed 23 kV system improvements, taken alone, as a fourth alternate approach to the proposed project.

a. Proposed Project

The Company's proposed project consists of a proposed facility plan and alternative facility plans. Under the proposal and Alternatives 1 and 2, the Company proposes improvements to the 115 kV system, consisting of approximately 14.5-19.0 miles of new and rebuilt circuits, in order to provide supplies to existing and possible new bulk substations (Exh. EFSC-1, pp. 5, 9, 11-12; Exh. EFSC-2, Need Q.12). In addition, under the proposal and Alternatives 1 and 2, the Company proposes improvements to the bulk substation system consisting of new and/or upgraded transformers, in order to provide supplies via the 23 kV distribution system (Exh. C-1, pp. 5, 6, 11-12). The Company indicated that the proposed and alternative facility plans all meet the basic reliability criteria identified by the Company (Exh. EFSC-2, Need Q.16) (see Section II.A.3.a, supra).

Finally, under the proposed and alternative facility plans, the Company proposes improvements to major elements of the 23 kV distribution system in order to provide supplies to all customers on distribution circuits in the area (Exh. C-1, pp. 3, 6; Exh. EFSC-12).

The Company indicated that its proposed transmission, bulk substation and distribution system improvements would reduce line losses and help ensure future system reliability (Exh. C-1, p. 5; Exh. C-2, pp. 22-23). The Company estimated that the 115 kV transmission and bulk substation components would reduce annual line losses by 80 to 570 kW in 1990, increasing to 200 to 1,500 kW in 2017, depending on the specific facility plan chosen (Exh. EFSC-4, IR 4.3).

Accordingly, based on the record, the Siting Council finds that the Company has demonstrated that the proposed project addresses the identified need in the Lower Cape.

b. No-Build Alternative

The Company considered a "no-build alternative," under which no action would be taken to provide additional energy resources to serve the Lower Cape (Exh. C-1, p. 11; Exh. C-2, p. 22).

The Company stated that the existing 23 kV distribution system on the Lower Cape is able to support peak demands up to a Cape division summer load level of only 260 MW with normal operations, and up to even lower load levels under outage contingencies (Exh. C-2, p. 22). Based on the most recently approved forecast, summer peak load currently exceeds 260 MW (see Table 1). The Company provided that load shedding would be required under a no-build alternative, and would extend to larger service areas for longer periods of time as load on the Lower Cape increases (Exh. CAPE-3, IR 2.14).

Accordingly, the Siting Council finds that the Company has demonstrated that the no-build alternative fails to address the identified need in the Lower Cape.

c. C&LM Alternative

The Company provided that C&LM is being initiated on the Lower Cape, and currently reduces peak load by approximately 1.0 MW (Exh. C-1, p. 11; Exh. C-2, pp. 22-23). However, the Company stated that implementation of C&LM sufficient to reduce the need for new transmission and distribution facilities cannot be obtained, and cannot be initiated in sufficient time to defer the need for new facilities (Exh. C-2, p. 23).

The Company indicated that it would further study C&LM strategies, and that it had set a target of 56 MW for the amount of peak load reduction that the entire Commonwealth system will achieve by 1995 (Exh. C-2, p. 11). The Company estimated that the Cape division's share of the 1995 load reduction target would be approximately 25 MW (id.). However, the Company noted that, because the 56 MW target for the Commonwealth system was based largely on potential reductions in commercial and industrial load, the allocated 25 MW share of the heavily residential Cape division probably is optimistic (Tr. 3, p. 192).

The Siting Council notes that a 25 MW reduction in peak load would be about one-third of the projected increase in load for the division between 1985 and 1995 (see Table 1). In addition, some of the reliability concerns that the Company has identified, i.e., the lack of back-up transmission to Harwich substation and the risk of overloading 23 kV feeder lines serving Chatham, present a problem even at existing load levels (see Sections II.A.3.b.i. and II.A.3.c, supra).

Still, the timing of other reliability concerns identified by the Company, notably the asserted need to rebuild the existing HT-H line, is less certain (see Section II.A.3.b.ii, supra). Thus, future load reductions resulting from C&LM programs potentially could delay the timing or reduce the sizing of some of the Company's proposed project elements.

Based on the record, the Siting Council finds that the Company has demonstrated that the C&LM alternative fails to address the identified need in the Lower Cape.

d. New Generation Alternative

The Company indicated that a new generation approach in the area likely would involve back-up or peaking capacity, as it would be inappropriate to "lock in" base load or intermediate capacity to a small area near the extremities of the distribution system (Tr. 8, pp. 37-38). However, the Company did not clarify how new generating capacity could be sited and designed to address the identified need in the Lower Cape.

Although the Company stated that the identified need in the Lower Cape relates to distribution (Exh. C-2, p. 23), new generation capacity could possibly meet the identified need in the Lower Cape. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Council compares the proposed project to the alternate approach of new generating capacity. See Section II.B.3, infra.

e. Low-Voltage Alternative[25]

The Company did not explicitly identify a low-voltage alternative as a possible solution to reliability problems in the Lower Cape. While the Siting Council does not require petitioners to analyze a low-voltage alternative, this proceeding includes a Company analysis of a significant upgrading of the 23 kV low-voltage system serving portions of the Lower Cape. This analysis enables the Siting Council to consider low-voltage improvements, alone, as one alternate approach to the proposed project. In past facility cases, the Siting Council has considered low-voltage approaches as one alternative to proposals to construct jurisdictional 115 kV transmission facilities. Cambridge Electric Light Company, 15 DOMSC 187, 215-216 (1987); Hingham Municipal Light Plant, 14 DOMSC 7, 21, 29, 31 (1986); Taunton Municipal Lighting Plant, 8 DOMSC 148, 161-162 (1981).

The Company provided load flow studies showing the effect of its low-voltage alternative on minimum voltage levels for 1990 summer peak load under normal conditions, and the effect of either a separate Harwich A-C outage or Orleans substation outage (Exh. CAPE-5, Q.82, pp. 104-106). Table 2 sets forth the minimum voltage levels for summer peak load in Chatham with the low-voltage alternative as compared with the existing system and the proposed project.

Table 2
Summer Peak Load Voltage in Chatham
Low-Voltage Alternative

	Normal Operation	Harwich A-C Outage	Orleans Outage
23 kV Improvements, 1990	1.014	.989	.978
Existing System, 1986	.978	.948	.908
Proposed Project[26], 1990	1.027	1.024	1.020

Sources: Exh. CAPE-5, Q.82, pp. 103-108; Exh. EFSC-1, IR 1.9; Exh. C-2, pp. 65, 67

25/ The low-voltage alternative consists of the 23 kV tie line and the 23 kV feeder line improvements. See Section I.C.2.a, *supra*.

26/ These voltages levels are based on the proposal.

The low voltage alternative alone would increase voltage levels significantly under both normal operations and outages of single transformers. In the event of the contingency of an outage of the Harwich A-C transformer or an outage at the Orleans substation, the low-voltage alternative would provide better voltage support than the existing system to meet the Company's voltage reliability criteria in Chatham through Summer 1990.

However, the Company's load flow analysis of the contingency of an Orleans substation outage shows that the 23 kV alternative would not address this contingency because the Harwich A-C transformer would be overloaded.[27] The Company provided that such overloading violates the Company's criteria for safe operation of the affected equipment and results in a further voltage drop beyond that shown in its load flow study (Tr. 9, pp. 178-179).

In the event of the contingency of the loss of the existing HT-H line (and the resulting loss of both Harwich substation transformers), the Company provided that it would need a much larger and more expensive distribution system (than that assumed in the proposed project) in order to reliably back up a loss of the existing HT-H line from Orleans and Hyannis Junction substations (Tr. 7, pp. 41-43). However, the Company's load flow analysis of this contingency is based on the existing low voltage system and thus does not reflect the improved distribution capabilities that the 23 kV alternative would provide. The load flow study shows that the already upgraded 23 kV system between Hyannis Junction and Harwich substations would allow the entire load normally served by the Harwich GE transformer to be supported from Hyannis Junction substation at a minimum voltage of .998 per unit (Exh. C-2, p. 81).

Still, the Company's analysis of the contingency of a loss of the existing HT-H line shows that, at only 80 percent of the forecasted

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27/ In its load flow analysis of the contingency of an Orleans substation outage, the Company assumed no ability to support an Orleans substation outage with power flow through any transformers other than the Harwich A-C and the Wellfleet GE transformers (Exh. C-2, p. 67). See Section II.A.3.c.i, supra.

1987 summer peak load, the power flow at Orleans substation would be 34.38 MVA, less than 6 MVA below the 40 MVA overload limit for that substation (Id., pp. 64, 81). With continued load growth, a loss of the existing HT-H line either would result in an overload of the Orleans substation or would require additional support from Hyannis Junction substation, extending into areas normally served by the Harwich AC transformer or Orleans substation. Such back-up support, carrying over long distances, would be unreasonable and could, as the Company contends, require extensive and more costly 23 kV improvements beyond the low-voltage alternative.

Accordingly, the Siting Council finds that the Company has demonstrated that the low-voltage alternative fails to address the identified need in the Lower Cape.

f. Conclusions on Project Approaches to the Identified Need

The Siting Council has found that the Company has demonstrated that the proposed project addresses the identified need in the Lower Cape. The Siting Council also has found that the Company has demonstrated that the (1) no-build alternative, (2) C&LM alternative, and (3) low-voltage alternative, fail to address the identified need in the Lower Cape.

Based on the record, the Siting Council finds that the proposed project is superior to the new generation alternative with respect to addressing the identified need in the Lower Cape.

3. Cost and Environmental Impacts

The Siting Council evaluates the proposed project and the new generation alternative with respect to cost and environmental impacts.

The Company estimated that construction of the 115 kV transmission and bulk substation components of the proposed project approach would cost $10.1 million to $12.5 million in nominal terms, and $3.5 million to $4.7 million in present value terms, depending on the specific facility plan chosen (Exh. EFSC-4, IR 4.4). The Company provided that construction of new generating capacity designed to meet the identified need on the Lower Cape would be economically unfeasible (Exhs. C-1, p. 11, C-2, p. 23). The Company stated that back-up or peaking capacity--the only type of generation the Company considers potentially capable of meeting the identified need for supplying load in Chatham--would be relatively small and very costly to operate (Tr. 8, pp. 37-38).

Given the expensive costs of maintaining and operating a generating plant, and the uncertain price stability of fuel sources needed to operate the plant, the Siting Council finds that the proposed project is superior to the new generation alternative with respect to cost in the Lower Cape.

With regard to environmental impacts, the proposed project approach (1) will involve some clearing of wooded areas and some construction in wetlands; (2) will result in increased visibility of transmission lines, distribution lines, and possibly substation equipment; (3) may require acquisition of land or easement rights for transmission, bulk substation and/or distribution system improvements; and (4) may cause increased noise and/or public health concerns relating to electrical effects (see Section III.E, <u>infra</u>).

Despite the environmental impacts associated with the proposed project, it is unclear whether the proposed project or the new generation alternative would be superior with respect to environmental impacts. The Company provided that construction of a new generating facility would be environmentally unsound (Exh. C-2, p. 23), but it did not provide specific environmental concerns. Clearly, however, the construction of new generating plant could raise siting, air quality, and fuel storage and handling concerns.

Accordingly, the Siting Council finds that the proposed project and the new generation alternate approach are comparable with respect to environmental impacts in the Lower Cape.

4. Conclusion: Weighing Need, Cost, and Environmental Impacts

The Siting Council has found that (1) the proposed project is superior to the new generation alternative with respect to addressing the identified need in the Lower Cape, (2) the proposed project is superior to the new generation alternative with respect to cost in the Lower Cape, and (3) the proposed project and the new generation alternative are comparable with respect to environmental impacts in the Lower Cape. On balance, the Siting Council finds that the proposed project is superior to the new generation alternative.

Accordingly, the Siting Council finds that Commonwealth has demonstrated that its proposed project is consistent with ensuring a necessary energy supply with a minimum impact on the environment at the lowest possible cost.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, sec. 69I requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternate approaches in terms of cost, environmental impacts, and addressing identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply. Northeast Energy Associates, 16 DOMSC 335, 381-409 (1987); Cambridge Electric Light Company, 15 DOMSC 187, 195-196, 229-237 (1987); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22-32 (1986); Massachusetts Electric Company, 13 DOMSC 119, 183-184, 190-248 (1985); Boston Edison Company, 13 DOMSC 63, 67-68, 76-81 (1985).

B. Description of the Proposal and Alternatives

1. Proposal

The Company's proposal consists of (1) constructing HOTL along the HOTL right of way, (2) constructing the Chatham substation which would be located on the HOTL route approximately half way between Harwich and Orleans substations, (3) rebuilding the existing HT-H line, and (4) upgrading the existing Wellfleet substation (Exh. C-1, p. 3, 6-7; Exh. EFSC-1, Need Q.7). The Company stated that the proposal will allow DOTL 1 to be removed (Exh. C-1, p. 5).

The Company provided that HOTL and Chatham substation would strengthen the power supply to the Lower Cape, thereby preventing anticipated low voltage and line capacity problems (id.). The Company stated that the Chatham substation would supply power to the 23 kV distribution system in the Chatham area, improving reliability as a result of the close proximity of the Chatham substation to the load center (id., p. 6; Exh. C-2, pp. 20-21). The Company also stated that HOTL is needed to supply Chatham substation and to serve as a back-up source of power to Harwich, Orleans and Wellfleet substations in the event either DOTL 2 or the existing HT-H line is out of service (Exh. EFSC-1, Need Q.1). Finally, the Company stated that rebuilding the existing HT-H line is needed to carry power flow in case DOTL 2 is out of service (Exh. EFSC-1, Need Q.1).

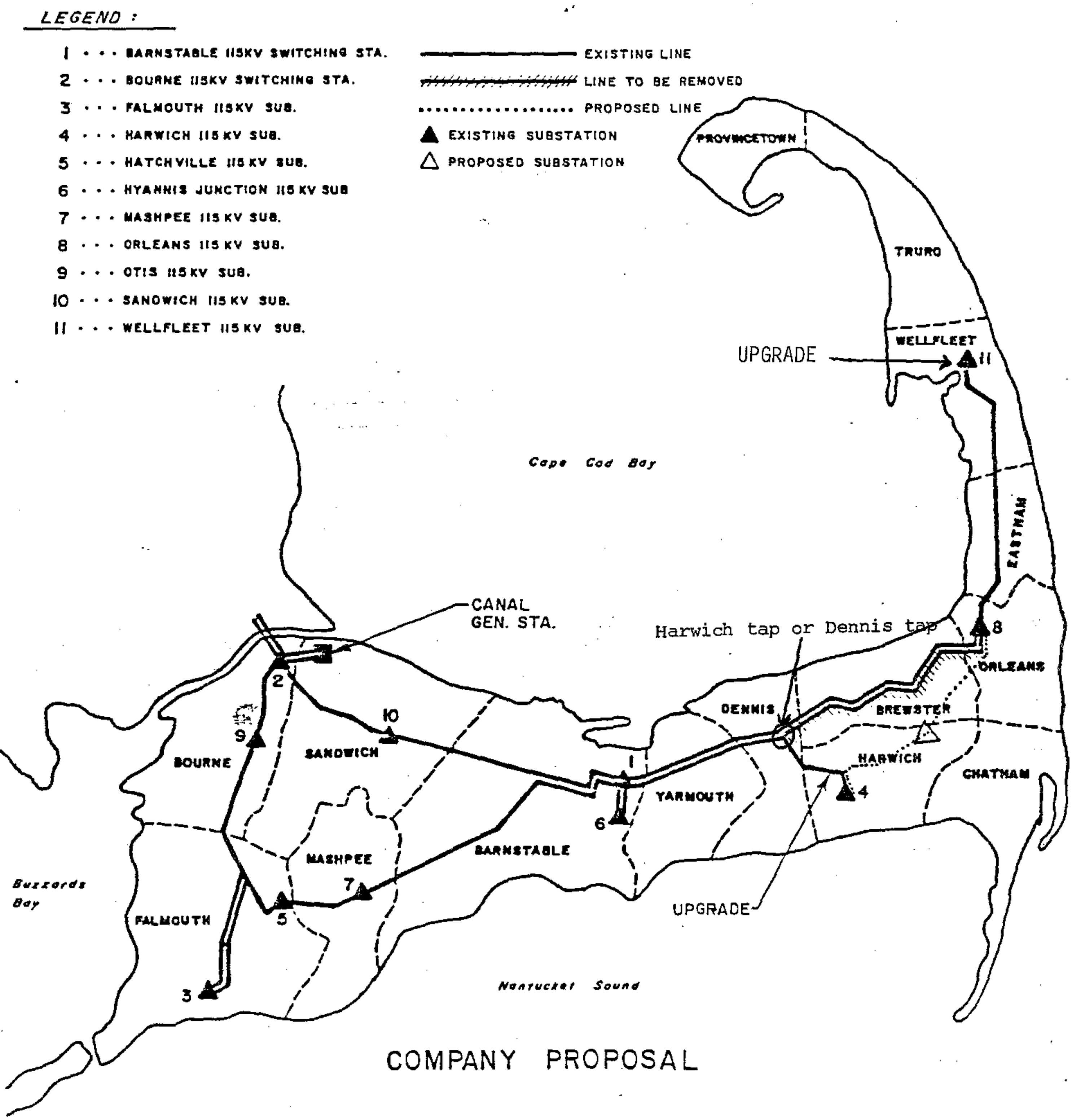
HOTL would be approximately 10 miles long, extending from Orleans substation approximately 3.5 miles along an expanded existing right of way parallel to an existing 23 kV line, then continuing for approximately 6 miles along an entirely new right of way to the area of Flax Pond in Harwich, and finally continuing for approximately .5 mile along the HT-H right of way, parallel to the existing HT-H line and an existing 23 kV line, to connect with Harwich substation (Exh. C-1, pp. 7, 9; Exh. EFSC-8). HOTL would consist of 795 kcmil, ACSR conductors on single-pole davit arm structures averaging 80 feet in height (Exh. C-1, p. 8). The 4.5-mile existing HT-H line would be rebuilt along its present center line, again utilizing 795 ACRS conductors and single-pole davit arm structures (Exh. EFSC-1, Need Q.7; Tr. 5, pp. 79-82). The Chatham substation would consist of an oil-cooled 30/40/50 MVA transformer and related equipment, built at a new site on Route 137 in East Harwich (Exh. C-1, p. 6).

The Company has placed its proposal into a longer-term facility plan, including future upgrades of the Wellfleet GE and Wellfleet Moloney transformers to 50 MVA banks in the years 2001 and 2015, respectively (Exh. EFSC-1, Need Q.7). The Company stated that these upgrades of Wellfleet substation will be needed to respond to the contingency of an Orleans substation outage (id.).

The Company's proposal is shown in Figure 3.

Figure 3

EXISTING 115 KV TRANSMISSION SYSTEM



COMPANY PROPOSAL

2. The Company's Alternatives

The Company's filing includes two facility alternatives to the proposal, identified as Alternative 1 and Alternative 2 (Exh. C-1, pp. 11-12; Exh. C-2, pp. 17, 69-72).

a. Alternative 1

Alternative 1 consists of (1) building the second HT-H line of 4.5 miles in length, (2) rebuilding DOTL 1, (3) rebuilding the existing HT-H line, (4) upgrading the existing 25 MVA A-C transformer bank at Harwich substation with a 50 MVA transformer bank, and (5) upgrading the existing Wellfleet substation (Exh. EFSC-1, Need Q.7; Exh. CAPE-4, Q.111, IR 3.9). The new and rebuilt transmission facilities included in Alternative 1 would be of similar design and capacity to those included in the Company's proposal (Exh. CAPE-2, Q.14).

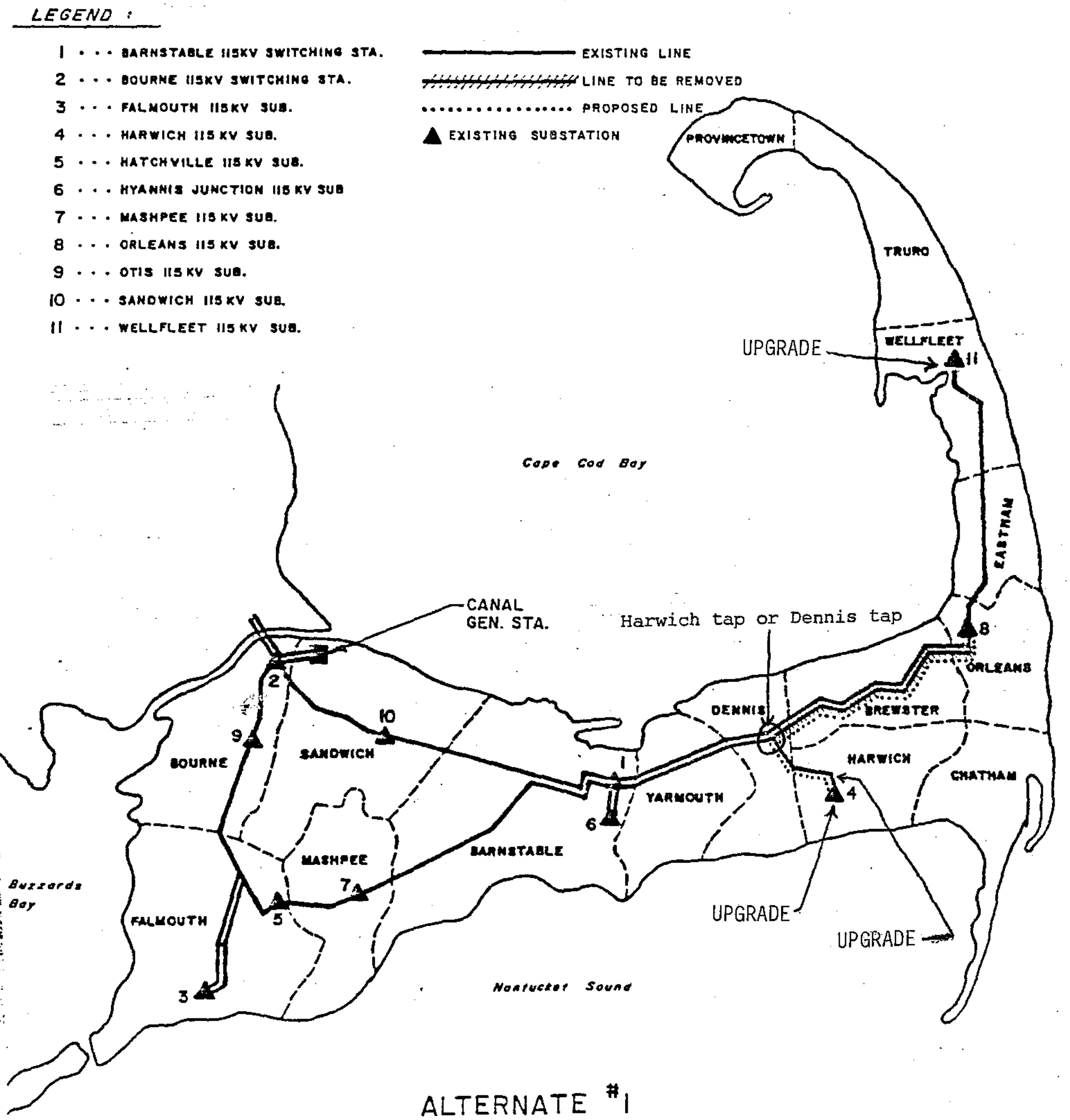
The Company indicated that it would need to build the second HT-H line and rebuild the existing HT-H line in order to provide necessary transmission support to Harwich substation (Exh. EFSC-1, Need Q.7; Exh. CAPE-4, Q.111, IR 3.9). Rather than removing DOTL 1, as in the proposed facility plan, the Company stated that it would rebuild DOTL 1 in order to provide a reliable back-up supply to Orleans and Wellfleet substations (Exh. EFSC-1, Need Q.7). The Company also stated that it would need to upgrade the Harwich A-C transformer under Alternative 1 in order to support the contingency of an Orleans substation outage (Exh. EFSC-1, Need Q.7; Exh. CAPE-2, Q.14).

The Company's long-term facility plan for this alternative provides that the Wellfleet GE transformer would be upgraded to a 50 MVA bank in 2001 and that the Wellfleet Moloney transformer would be upgraded to a 50 MVA bank in 2112 (id.). The Company stated that Wellfleet substation would carry more of the area load under Alternative 1 than under the Company's proposal, thereby requiring the earlier upgrade of the Moloney transformer than would be needed under the Company's proposal (Exh. CAPE-1, Q.16a).

Alternative 1 is shown in Figure 4.

Figure 4

EXISTING 115 KV TRANSMISSION SYSTEM



ALTERNATE #1

b. Alternative 2

Alternative 2 consists of (1) building HOTL along the HOTL right of way, (2) rebuilding the existing HT-H line, (3) upgrading the existing 25 MVA AC transformer bank at Harwich substation with a 50 MVA transformer bank, and (4) upgrading the existing Wellfleet substation (Exh. C-1, p. 3, 6-7; Exh. EFSC-1, Need Q.7). As with the proposal, installation of HOTL under this Alternative may allow DOTL 1 to be removed (Exh. C-2, Exhibit 13).

The Company stated that HOTL and the rebuilt HT-H line would enable the Company to meet expected peak load and provide needed back-up transmission to Harwich substation (Exh. EFSC-1, Need Q.7). In addition, the Company provided that HOTL would provide an additional back-up supply to Orleans and Wellfleet substations, thereby allowing the removal of DOTL 1 (id.). The Company also stated that the Harwich A-C transformer would be upgraded under Alternative 2 in order to meet the contingency of an Orleans substation outage (Exh. EFSC-1, Need Q.7; Exh. CAPE-2, Q.14).

The Company's long-term facility plan provides that the Wellfleet GE transformer would be upgraded to a 50 MVA bank in 2001 and that the Wellfleet Moloney transformer would be upgraded to a 50 MVA bank in 2112 (id.).

Like the proposal, Alternative 2 would include building HOTL along the HOTL right of way, with the associated impacts of new and expanded right of way. Yet, like Alternative 1, Alternative 2 would essentially rely on the existing substation configuration in the Lower Cape, and would only provide for upgrading existing transformers in conjunction with 23 kV improvements to bring about needed improvements in distribution capability. Overall, Alternative 2 appears to have the principal limitations of both the proposal and Alternative 1, and not provide any major advantages. Accordingly, the Siting Council substantially limits its further consideration of Alternative 2 in the remainder of this review.

3. Other Alternatives

In response to requests by intervenors and the Siting Council staff, the Company developed and provided evidence regarding three additional alternatives. Two of these alternatives involved variations on Alternative 1, providing additional transformer capacity in either the Orleans or Brewster area. The third alternative, a variation on the Company's proposal, involved underground construction of portions of HOTL.

None of the three additional alternatives was set forth in the Notices of Adjudication and Public Hearing in this proceeding. Thus, the Siting Council cannot approve any of the facilities contained in these alternatives as part of this proceeding. These alternatives are included in the proceeding in order to help elucidate advantages and disadvantages of the proposal and the Company's alternatives, and enhance the basis for determining whether or not the proposal or the Company's alternatives would provide a necessary energy supply at the least cost and with a minimum impact on the environment.

a. Brewster Substation Alternative

In response to a request by the Siting Council staff, the Company considered a variation of Alternative 1, providing for a new 50 MVA substation to be located along or near the DOTL right of way in South Brewster, approximately half way between Dennis tap and Orleans substation ("Brewster substation") (Exh. EFSC-3, Q.32). Brewster substation would be located approximately 3.5 miles north of the site of the proposed Chatham substation (id.). Similar to Alternative 1, the Company would rebuild DOTL 1 and the existing HT-H line, and build the second HT-H line (id.). Unlike Alternative 1, however, the Harwich A-C transformer would not be upgraded. As part of the Company's long term facility plan for this alternative, the Wellfleet GE transformer would be upgraded to a 50 MVA bank in 2001 and the Wellfleet Moloney transformer would be upgraded to a 50 MVA bank in 2115 (Exh. EFSC-4, IR 4.1).

Thus, the Brewster substation alternative is identical to

Alternative 1 with respect to transmission improvements and related right of way impacts, but differs significantly from the proposal and Alternative 1 in terms of substation configuration and related implications for distribution capability in the Lower Cape. The Siting Council limits its further consideration of this alternative to those portions of the review where significant differences from other facility plans help elucidate the issues.

b. Double-End Orleans Substation Alternative

CAPE requested that the Company consider a variation of Alternative 1, under which the existing 25 MVA Harwich A-C transformer, to be retired under Alternative 1, would be relocated to Orleans substation to provide "double-end" capability there (Exh. CAPE-7, Q.123).[28] During the proceeding, this variation of Alternative 1 became known as the double-end Orleans substation alternative. Similar to Alternative 1, the Company would rebuild DOTL 1 and the existing HT-H line, build the second HT-H line, and upgrade the Harwich A-C transformer to a 50 MVA bank (id.). As part of the Company's long term facility plan for this alternative, the Wellfleet GE transformer would be upgraded to a 50 MVA bank in 2001 and the Wellfleet Moloney transformer would be upgraded to a 50 MVA bank in 2115 (Exh. EFSC-4, IR 4.1).

The double-end Orleans substation alternative is identical to Alternative 1, except that an additional transformer would be installed at the existing Orleans substation. As such, this alternative is not mutually exclusive with any component of Alternative 1, but merely includes an additional component which could be added in the future anyway. Accordingly, the Siting Council

28/ The Company stated that a second transformer probably could not be accommodated on the immediate site of Orleans substation, which is located in a built-up area (Tr. 10, pp. 28-30). The Company assumed the second transformer would be sited on adjacent Company-owned property across the street, which is near a residential area (id., pp. 30-31, 69-70).

substantially limits its further consideration of the double-end Orleans substation alternative in the remainder of this review.

c. Underground/Overhead Alternative

Ovaska requested the Company to provide information about the cost of underground construction, relating to a possible alignment of HOTL through Harwich Golf Course (Exh. EFSC-5, Q.4a). The Siting Council staff requested that the Company consider additional options for underground construction along longer portions of the HOTL route, such as to avoid above-ground construction near other property owners and environmentally significant areas as well (Tr. 12, pp. 55-59, 66-71, 79-82). During the proceeding, these options collectively became known as the underground/overhead alternative.

In response, the Company provided route descriptions and cost estimates for four underground/overhead options, incorporating 1.5 to 5.1 miles of underground construction along streets in areas between Harwich substation and the proposed Chatham substation (Exh. EFSC-25). For each option, the Company identified the affected streets, endpoints and terminal site requirements for the underground segment (id.).[29]

29/ The four underground/overhead options considered by the Company are: (1) underground along streets from Harwich substation to Chatham substation, following Old Chatham Road, Route 39 and Route 137, then overhead along the HOTL route to Orleans substation; (2) overhead along an overland route for a distance of 0.85 miles from Harwich substation to a point on Queen Anne Road, then underground along Queen Anne Road, Route 39 and Route 137 to Chatham substation, then overhead along the HOTL route to Orleans substation; (3) overhead along an overland route from Harwich substation to a point on Queen Anne Road, then underground along Queen Anne Road, Lakeway Lane and Quails Nest Run to a Company-owned site at Seth Whitefield Road, then overhead along the HOTL route to Orleans substation; and (4) overhead along the HOTL route from Harwich substation to Queen Anne Road near Eldredge Pond (also known as Cornelius Pond), then underground along Queen Anne Road, Lakeway Lane and Quails Nest Run to a Company owned site at Seth Whitefield Road, then overhead along the HOTL route to Orleans substation (Exh. EFSC-25).

The underground/overhead alternative would require more costly underground construction than the proposal and Alternative 1 in places, but would provide a transmission and substation configuration identical to that of the proposal. Although the underground/overhead alternative would reduce requirements for new right of way in areas of environmental concern, this alternative still would result in more right of way impacts than Alternative 1. Given that the underground/overhead alternative is more costly and has greater right of way impacts than Alternative 1, the Siting Council substantially limits its further consideration of this alternative in the remainder of the review.

C. Site Selection Process

The Siting Council reviews the overall approach used by the Company to identify the proposal and alternatives from among a wider range of choices. As part of its review of the Company's site selection, the Siting Council considers whether or not the Company examined a reasonable range of practical facility siting alternatives.

1. The Company's Siting Analysis

The Company provided information illustrating its selection process on two different levels. First, the Company presented a review of a range of overall 115 kV configurations in the Lower Cape that could address reliability problems. Second, the Company described possible minor routing variations that it considered relating to areas along the HOTL route.

a. Overall Facility Configurations

The Company developed two alternatives for detailed analysis and comparison with the proposal, and during the proceeding considered three additional alternatives (see Section III.B, *supra*). The Company indicated that all the alternatives it analyzed in detail meet the basic reliability criteria identified by the Company, and provide comparable but not identical reliability to the proposal (Exh. EFSC-2, Need Q.16) (see Section II.A.3.a, supra).

In addition to the above alternatives, the Company indicated it initially considered four other facility alternatives in the Chatham area (Exh. EFSC-2, Need Q.11). The four alternatives all included the proposed Chatham substation, but incorporated different transmission routes to supply the substation (id.). In addition, all the alternatives included double radial lines along the HT-H right of way and along part or all of the DOTL right of way, as necessary to supply Harwich and Orleans substations (id.).

The four additional alternative 115 kV transmission routes considered by the Company to serve Chatham substation included (1) a double-circuit radial line extending to Chatham from a point on the DOTL line approximately half way between Dennis tap and Orleans substation ("Brewster tap"), (2) a single-circuit radial line extending along the HOTL right of way from Harwich substation to Chatham, (3) a single-circuit radial line extending along the HOTL right of way from Orleans substation to Chatham, and (4) a loop or "dual-feed" line extending from Brewster tap to Chatham and then along the HOTL route from Chatham to Orleans substation (id.). The Company compared these four additional alternatives to the proposal and Alternatives 1 and 2, based on total circuit miles of construction (id., Need Q.12), and concluded that the four additional alternatives amounted to more costly variations of Alternatives 1 and 2 (Exh. EFSC-1, Need Q.3). The Company stated that environmental factors were not considered in the initial site screening process (Exh. EFSC-2, Need Q.11).

b. Minor Variations in HOTL and HOTL Route

In the second level of its site selection process, the Company identified and considered minor variations in siting HOTL, and made some changes in the HOTL route as well as in HOTL's placement within the right of way. The Company's consideration of such minor variations has been focused in two areas along the HOTL route--Hawksnest State Park and the Harwich Golf Course.

i. <u>Hawksnest State Park</u>

The HOTL route extends through the southern portion of Hawksnest State Park in Harwich, closely paralleling the park boundary in the area of Beach Plum Circle and Quails Nest Run. The Company stated that, when it first began developing its plan for HOTL in the late 1960's, it identified a more northerly route passing through the middle of the park (Tr. 4, pp. 32-34). However, as part of its efforts to obtain the right to construct facilities through the park, the Company considered alternate routes nearer to the perimeter of the park or outside of the park (id., pp. 21-45).

The Company provided a map showing four possible routes it considered in the Hawksnest Park area, including the HOTL route (Exh. EFSC-1, IR 1.13). The Company indicated that it rejected two of the alternate routes, including the only route that would circumvent the park, because it expected that these routes would cause significant land use and visual impacts in developed areas and at street crossings (Tr. 4, pp. 24-27; pp. 159-160). Over a 10-year period, the Department of Environmental Management ("DEM") and its predecessor, the Department of Natural Resources ("DNR"), pursued both underground construction and perimeter routing of the proposed facilities within the park in order to minimize any intrusion of the proposed facilities on the park as a whole (id., pp. 22-45; Tr. 11, pp. 150-207). Gilbert Bliss, Director of DEM Division of Forests and Parks and a witness for Innis, indicated that DEM eventually agreed to support legislation authorizing an easement for overhead lines on a route along the southern boundary of the park, provided that HOTL was approved as necessary and no other segment of HOTL was to be constructed underground (Tr. 11, pp. 172, 183-184, 191-192). In 1982, the Massachusetts Legislature authorized DEM to grant an easement for overhead lines along the HOTL route (id., pp. 46-47).

In response to arguments by Innis (Innis Brief, pp. 2-10), the Company agreed to modify its proposal by shifting the placement of HOTL from the southern side to the northern side of the HOTL right of way through the park and surrounding areas between Eldredge Pond and the proposed Chatham substation (Company Brief, p. 20-21).

ii. Harwich Golf Course

The HOTL route east of the crossing of Oak Street in Harwich would extend through wooded and wetland areas bordering the northwest edge of land currently utilized as part of the Harwich Golf Course, also known as Cranberry Valley Golf Course (Exh. EFSC-3, IR 3.5). North of the golf course, the route would continue across wetlands on the western portion of a parcel owned by Ada Litchfield, a member of CAPE, then cross Queen Anne Road, then traverse a parcel owned by Ovaska, then cross Eldredge Pond, and then extend onto land owned in part by the Company on the east shore of the pond (id.).

The HOTL route in the vicinity of the Harwich Golf Course and Eldredge Pond represents a variation from the originally proposed route in the proceeding, providing for overhead lines directly across Harwich Golf Course (Exh. C-1, Appendix C-1). In 1974, the Town of Harwich had authorized the Harwich Golf Course Commission ("Golf Course Commission") to grant an easement to the Company for an underground alignment of HOTL across the Harwich Golf Course (Exh. EFSC-1, Right of Way Q.4; IR 1.16). In ensuing years, the Company had attempted to persuade the Golf Course Commission to accept overhead lines, and by 1981 had begun considering alternate routes through the golf course area (id.; Tr. 4, pp. 97-101).

In the proceeding, the Company identified four alternate routes passing generally to the north of the Harwich Golf Course, although two of these routes still would cross an unused corner of the golf course land (Exh. EFSC-6; Exh. EFSC-3, Right of Way Q.8, IR 3.5). The Company identified its preferred route (HOTL route)(Exh. EFSC-3, Right of Way Q.8, IR 3.5), the only route traversing Eldredge Pond, after acquiring rights to cross Ovaska's property on the southwest shore of Eldredge Pond in December 1986 (Exh. EFSC-3, IR 3.6, updated).

2. Adequacy of Site Selection and Range of Alternatives

The record shows that the Company initially considered a number of alternate 115 kV configurations that would serve area load via the proposed Chatham substation, as well as Alternative 1 and Alternative

2, which would serve area load via upgraded capacity at existing substations. The Company rejected all of the alternatives that would include Chatham substation, except for the proposal, based on the relatively high numbers of circuit miles that would be required.

The Company initially failed to present an alternative that included a new substation at a different location than the proposed Chatham substation site (Exh. EFSC-3, Need Q.32). During the proceeding, however, the Company developed the Brewster substation alternative, which provides for a new substation at an undetermined site in the South Brewster area, near an existing right of way (id.; Exh. EFSC-4, Need Q.35).

With respect to the consideration of minor variations of the HOTL route, the Company analyzed a significant range of choices to address apparent siting conflicts at two points along the HOTL route, Hawksnest State Park and Harwich Golf Course. The range of alternate routes considered in those areas was adequate for the concerns that were raised.[30]

The Siting Council finds that the Company developed and applied a reasonable set of criteria for identifying possible overall transmission configurations. The Siting Council also finds that the Company considered a reasonable range of practical facility siting

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30/ In selecting routes through these areas, the Company resisted over a number of years the efforts of the owners of both Hawksnest State Park and Harwich Golf Course to restrict the Company to underground construction, and finally worked with the two governmental landowners to select more agreeable alternate routes near the perimeters of the respective public landholdings (Tr. 4, pp. 22-45, 97-101; Tr. 11, pp. 150-207). However, some abutters opposed various alternate routes in both areas and expressed concern that abutters' interests were not adequately considered in the siting process (Innis Brief, pp. 13, 15-16; Tr. 7/18/85, pp. 98-122; Tr. 1/27/87, pp. 47-48, 62-67). As a general rule, a company should attempt to obtain representation of as wide a range of affected interests as possible when consulting with landowners about facility siting options in locations of potential controversy or community concern. During the proceeding, the Company did present a number of underground/overhead options that would avoid or minimize environmental impacts in the affected areas (see Section III.B.3.c, supra).

alternatives including the Company's alternatives and the alternatives suggested by the intervenors and Siting Council staff.[31]

D. Cost Analysis of the Proposal and Alternatives

1. The Company's Cost Analysis

The Company based its economic analysis primarily on calculations of cumulative present-value capital and operating costs over a 30-year period for the proposal and each of the alternatives. The Company provided estimated capital costs for the proposal and all alternatives, and provided an approximate breakdown of the capital costs for transmission and substation elements under the proposal and Alternatives 1 and 2 (Exhs. EFSC-4, IR 4.1, EFSC-25; Exh. CAPE-3, Q.42, Q.43, Q.44). The Company provided the results of computer runs[32] developing 30-year net present value revenue requirements for the period 1988-2017, expressed in 1987 present-value terms (Exh. EFSC-4, IR 4.2).

In addition, the Company estimated the economic value of line loss savings for the Cape division for the years 1988-2017 under each of the proposed and alternate facility plans, as compared to the

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31/ Since the Siting Council found that the 23 kV tie line is a non-jurisdictional facility, the Siting Council also found that the Company is not required to file an alternative that does not utilize the HOTL right of way in order to demonstrate that it presented a reasonable range of practical facility siting alternatives. See Section I.C.2.b, supra.

32/ The Company did not perform a 30-year computer analysis of net present value revenue requirements for the underground/overhead alternative. Instead, the Company used a simple ratio of 1988 capital costs to 1988-2017 net present value revenue requirements in order to derive the 30-year net present value revenue requirements for the four options under the underground/overhead alternative (Exh. EFSC-25). The Company stated that this approach was reasonable because its analysis of 30-year net present value revenue requirements for transmission and substation elements essentially assumed, for respective elements, a parallel relationship by year between the level of capital expenditures and the impact on net present value revenue requirements (Tr. 9, pp. 84-87).

existing 115 kV system with the Company's proposed 23 kV improvements alone (Exh. EFSC-4, IR 4.3). The Company then determined the differences between the proposal and the respective alternatives with respect to 30-year line loss savings, and entered these differences as additional operating costs in the 30-year net present value revenue requirements analyses for the respective alternatives (id., IR 4.2).

The results of the Company's 30-year cost analysis are shown in Table 3.

Table 3
Present Value Capital Cost (PVCC)
and 30-Year Present Value Revenue Requirements (PVRR), 1988-2017
Proposed and Alternative Facility Plans
($ millions)

		30-Year PVRR		
Proposal and Alternatives	PVCC	Net 30-Year PVRR	Line Loss Adjustment	Total Present Value Cost
Company Proposal	3.53	7.45	0	7.45
Alternative 1	4.26	9.15	2.27	11.42
Alternative 2	3.56	7.59	2.27	9.86
Brewster Substation	4.23	9.01	0.41	9.42
Double-End Orleans	4.70	10.07	1.17	11.24
Underground/Overhead				
Option 1	10.57	20.10	0	20.10
Option 2	10.45	19.89	0	19.89
Option 3	8.69	16.72	0	16.72
Option 4	6.13	12.12	0	12.12

NOTE: The line loss adjustment column reflects the value of additional line losses above those of the proposed plan, if any.

Source: Exhs. EFSC-4, IR 4.1 through IR 4.4, EFSC-25.

The results of these analyses show that only Alternative 2 is comparable to the Company's proposal with respect to present value capital costs, and 30-year net present value revenue requirements exclusive of line losses. However, when 30-year net present value revenue requirements are adjusted to reflect line loss savings, the Company's analysis shows that the proposal is the least cost facility plan.

The Siting Council finds that the Company used an appropriate and reviewable general approach in compiling its analysis of costs of the proposal and alternatives. The Siting Council addresses certain adjustments to the Company's cost analysis in the following section.

2. Adjustments to Company's Cost Analysis

A number of additions or adjustments to the cost analysis were considered during the course of the proceeding, including: (1) adjustments to cost of major facility elements, (2) right of way costs and (3) adjustments to line loss savings.

a. Major Facility Elements

During the course of the proceeding, possible cost adjustments to the proposed and alternate facility plans were considered with respect to (1) upgrading the Harwich A-C transformer under the Company's proposal, (2) rebuilding the existing HT-H line under Alternative 1, and (3) substituting a double-circuit HT-H line for two single-circuit HT-H lines under Alternative 1.

CAPE argues that, under the proposal, the Harwich A-C transformer would have to be replaced due to its advanced age and limited rating (CAPE Brief, p. 15). Noting that replacement of the Harwich A-C transformer with a new larger transformer is part of Alternative 1, CAPE asserts that a similar upgrade and cost impact should be assumed as part of the proposal (id.)

The Company asserts that the Harwich A-C transformer does not need to be upgraded if the Company makes the facility improvements in its proposal (Company Reply Brief, pp. 4-5). The Company maintains that, if it were to make the suggested upgrade under the proposal, certain economic benefits, notably additional line loss savings, would result (id., p. 5).

The Company acknowledged that the Harwich A-C transformer is old, but could not provide its actual age (Tr. 7, p. 30). CAPE's witness, Mr. Kusko, stated that Allis Chalmers, the manufacturer of this transformer, stopped manufacturing large transformers 20-25 years ago, a claim the Company did not dispute (Tr. 15, p. 115). The Company assumed a transformer of the size of the Harwich A-C transformer in its long-term analyses of load flow and line losses, but acknowledged that the Company would replace that transformer "if it became a problem, if it started overheating or had any kind of problem at all" (Tr. 7, pp. 31-32). Still, the Company provided that there would be no need to upgrade the transformer to a larger size within the 30-year time frame of the Company's analysis (id.).

Based on the record, there is little merit to CAPE's assertion that the Harwich A-C transformer would need to be equally large under the proposal and Alternative 1. As presented by the Company, the proposal already surpasses Alternative 1 in terms of overall transformer capacity in the Lower Cape, and would be overburdened if still more capacity were added by including an upgraded 50 MVA transformer in place of the existing Harwich A-C transformer.

However, the Siting Council notes that the Company's proposal still would rely on a transformer at least 20-25 years old. The Company acknowledged that the expected life of a transformer is between 30 and 40 years (Tr. 7, pp. 28-30). Based on this expected life, the Harwich A-C transformer would exceed its expected life during the 30-year time frame of the Company's analysis. Therefore, for purposes of this review, it would be reasonable to include in the cost of the proposal the cost of replacing the Harwich A-C transformer at its present size when the transformer exceeds its planned life.

Although a replacement year was not identified, based on the Harwich A-C transformer being at least 20-25 years old, this transformer would reach its planned life of 30 to 40 years by the year 2000 or within a few years thereafter (Tr. 7, pp. 28-30; Tr. 15, p. 115). The Siting Council notes that the Company expects to upgrade the Wellfleet GE transformer to 50 MVA in approximately the same time period, specifically in 2001, at a net present value revenue requirement of $787,749 (Exh. EFSC-4, IR 4.1, IR 4.2).[33] Given that the Harwich A-C transformer, when replaced, would have half the capacity of the upgraded Wellfleet GE transformer, the Siting Council assumes for purposes of this review that, under the proposal, the Harwich A-C transformer would be replaced within 30 years at a net present value revenue requirement of $393,875.

Accordingly, the Siting Council finds that it is reasonable to assume that the Harwich A-C transformer would exceed its planned life and need to be replaced in or about 2001.[33A] Therefore, the Siting Council finds that the total present value cost of the proposal is $393,875 higher than the level estimated by the Company.

Two additional adjustments considered in the review relate to the Company's expectation that, under Alternative 1, it would be necessary to both rebuild the existing HT-H line and build the second HT-H line in 1988. The Company considered (1) whether the cost of Alternative 1 could be reduced by delaying the rebuilding of the existing HT-H line beyond 1988 (Tr. 8, pp. 45-62), and (2) whether the cost of rebuilding the existing HT-H line and building the second HT-H line could be reduced by building a double-circuit line (Tr. 15, pp. 110-111).

With respect to delaying the rebuilding of the existing HT-H line beyond 1988, the Company stated that it is justifiable to replace the line now because of its outdated design (Tr. 8, p. 47). However, the

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33/ The Company estimated that an upgrade of the Wellfleet GE transformer to 50 MVA in 2001 would reflect a capital cost of $1,000,000 (1985 cost level) and a 1988 to 2017 net present value revenue requirement of $787,749 (Exh. EFSC-4, IR 4.1, IR 4.2). By comparison, replacement of the Harwich A-C transformer at its current 25 MVA capacity, half the planned capacity of the upgraded Wellfleet GE transformer, likely would involve a smaller capital cost (1985 cost level) and, if implemented in 2001, a correspondingly smaller net present value revenue requirement based on the Company's cost methodology.

33A/ Assuming the age of the transformer is 22.5 years (the midpoint of the 20 to 25 year range when Allis Chalmers stopped manufacturing transformers) and the expected life of the transformer is 35 years (the midpoint of the 30 to 40 year range specified by the Company), the transformer would reach the end of its expected life in or about 2001.

Company acknowledged that the existing HT-H line is 29 years old and concluded that this line likely would provide adequate back-up capability for a number of years beyond 1988 (id., pp. 45-47). With respect to possible economic savings, the Company estimated that delaying the $869,000 capital cost of the rebuilt line from 1988 to 1991/1992, when the existing HT-H line would be 32.5 years old, would reduce the present value capital cost by $134,725 (id., p. 76). While adjustments to some carrying costs also might apply, the Company provided that operating and maintenance costs would not be increased following the rebuilding and thus should not be adjusted to reflect the delay (id., pp. 60-62).

Accordingly, the Siting Council finds that it is reasonable to assume that the Company could delay rebuilding the existing HT-H line under Alternative 1 until 1991/92. Therefore, the Siting Council finds that the total present value cost of Alternative 1 is $134,725 lower than the level estimated by the Company.

With respect to building a double-circuit line, CAPE provided that the cost of rebuilding the existing HT-H line and building the second HT-H line in 1988 could be reduced by 25 percent with such construction (Tr. 15, pp. 110-111). However, the Company stated that, based on its experience, steel poles have been twice as expensive as wood poles (Tr. 17, p. 212; Exh. C-14). Thus, the record is unclear as to whether the cost of rebuilding the existing HT-H line and building the second HT-H line would be reduced by building a double-circuit line.

In sum, the Siting Council has found that (1) it is reasonable to assume that the Harwich A-C transformer would exceed its planned life and need to be replaced within the 30-year period used in the Company's analysis, and (2) as a result, the total present value cost of the proposal is $393,875 higher than the level estimated by the Company. The Siting Council also has found that (1) the Company could delay rebuilding the existing HT-H line under Alternative 1 from 1988 to 1991/92, and (2) as a result, the total present value cost of Alternative 1 is $134,725 lower than the level estimated by the Company.

b. Cost of HOTL Right of Way and Chatham Substation Site

The Company has proposed a set of 23 kV improvements that includes, under all alternatives, the 23 kV tie line initially extending along a portion of the HOTL right of way from Orleans substation to Pleasant Lake Avenue in Harwich, and eventually extending along the entire right of way to Harwich substation (see Section I.C.2.a, supra). Based on its position that the 23 kV tie line along the HOTL right of way is necessary under all alternatives, the Company argues that the costs of right of way acquisition need not be considered in comparing alternatives (Company Brief, pp. 43-48). The Company further argues that, if the 23 kV tie line along the HOTL right of way is not to be viewed as part of some alternatives, then the relative costs of alternate 23 kV configurations must be considered along with relative right of way costs (Company Brief, pp. 45-46).

CAPE argues that right of way acquisition costs must be added to the proposal--a position consistent with CAPE's suggestion of an alternate 23 kV configuration, under Alternative 1, that avoids use of the HOTL right of way (CAPE Brief, p. 15).[34] CAPE asserts that the record is not detailed enough with respect to possible 23 kV improvements, and therefore disagrees with the Company's position that relative 23 kV improvement costs should be considered if the HOTL right of way is not utilized for the 23 kV tie line (CAPE Reply Brief, p. 4).

34/ To meet a design condition of 1990 peak load with an outage of Orleans substation, CAPE suggested an alternative 23 kV configuration consisting of (1) upgrading to 797 ACSR the portion of the 1/0 line from Orleans substation to Freeman's Way, (2) upgrading to 795 ACSR a 0.7 mile segment of the existing 477 ACSR feeder line from Harwich substation to the West Harwich distribution circuit, and (3) upgrading to 477 ACSR the remainder of the 1/0 line from Freeman's Way to Route 39 near Harwich (Tr. 15, pp. 84-85). CAPE provided that further upgrades of the 1/0 line would need to be made to meet 1997 peak load under the outage of the Orleans substation (Tr. 15, pp. 86, 90; Tr. 16, pp. 57, 88).

In finding that the 23 kV tie line is not jurisdictional, the Siting Council stated that (1) it does not endorse use of the HOTL right of way for the 23 kV tie line, and (2) in light of the cost and environmental impacts that would be incurred, the use of the HOTL right of way for a 23 kV distribution line seems wholly inappropriate (see Section I.C.2.b, supra). Further, the Company provided that it could make the necessary 23 kV improvements along town and state roads (Tr. 13, pp. 88-90; Tr. 14, pp. 104-105) (see Section I.C.2.b, supra). Therefore, the Company has failed to establish that acquisition of the HOTL right of way is required under Alternative 1. Accordingly, the Siting Council finds that the acquisition costs for the HOTL right of way, as well as the Chatham substation site which is not required under Alternative 1, is considered as part of the proposal but not Alternative 1.

The Company provided that, as of March 1987, it had spent $1,288,841 in direct and indirect costs to acquire fee and easement rights for the proposed HOTL right of way and Chatham substation site (Exh. CAPE-6, Tab 97).[35] The Company estimated that an additional $796,900 in direct and indirect costs would be required to acquire the remainder of the HOTL right of way, including $411,144 for acquiring rights from known landowners and $385,756 for acquiring pro tanto rights to land from unknown owners (Exh. EFSC-26A; Tr. 14, pp. 64-65).

CAPE argues that the Company's estimate reflected an unrealistically low cost-per-acre factor for the overall remaining acquisition cost (CAPE Brief, pp. 15-16). Stating that the Company's estimate is a "low end" figure, CAPE suggests $15,604,166 as a "high end" figure for acquiring all remaining rights of way, based on the per-acre direct cost that the Company paid to acquire rights across Ovaska's parcel (id.). CAPE then suggests $1,600,000 as a realistic

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35/ The Company also estimated it could recover $1,736,250 by selling its fee interests in the HOTL right of way and the Chatham substation site, including $1,298,750 for the HOTL right of way and $437,500 for the Chatham substation site (Exh. CAPE-6, Tab 101). Thus, if Alternative 1 is implemented, the Company could more than recover the direct and indirect costs of $1,288,841 already incurred in acquiring the HOTL right of way and Chatham substation site.

cost estimate for the remainder of the HOTL right of way, based on the cost of the first 108 acres and taking into account inflation and increased difficulty in acquiring the remaining rights (id.). CAPE also asserts that the Company should include the value of land owned by the Company in Fairhaven, Massachusetts that, according to CAPE, the Company plans to exchange for the right to cross Hawksnest State Park (id., p. 17).[36]

The record shows that, based on consultation with independent appraisers, the Company estimated that it could acquire easement rights from unknown landowners at an average direct cost of $5,000 per acre--half the assumed value of $10,000 per acre for the affected land (Tr. 14, pp. 4-14). The Company provided that the estimated acquisition cost attributable to direct payments for acquiring the remaining 8.54 acres from known landowners amounts to an average of nearly $15,000 per acre (id., p. 53).

The per-acre payments to known landowners of nearly $15,000 is comparable to the per-acre cost reflected in CAPE's own estimate of $1,600,000 to acquire the overall 102.17 acres remaining. While the price of $10,000 per acre for land classified as "owners unknown" is below CAPE's estimate, there is little basis for the Siting Council to reject the Company's approach to estimating this cost.

In sum, the Siting Council has found that the acquisition costs for the HOTL right-of-way and Chatham substation site are considered as part of the proposal but not Alternative 1. Accordingly, the Siting Council finds that the Company's 30-year present value cost analysis is adjusted to reflect $2,085,741 in direct and indirect

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36/ The Company stated that no such exchange has been agreed to, but acknowledged that if such an exchange were made, the value of the land in Fairhaven should be considered a part of the cost of the HOTL right of way (Tr. 14, pp. 23-25). The Siting Council notes that the prospective easement through Hawksnest State park, as legislatively authorized, includes 8.94 acres (Exh. Bliss-4), and thus clearly has not been included in the 8.54 acres the Company expects to acquire from known owners. Therefore, the cost to acquire an easement of 8.94 acres in Hawksnest State Park may increase the overall HOTL right of way acquisition cost as estimated by the Company.

costs for acquisition of the HOTL right of way and the Chatham substation site under the proposal, including $1,288,841 in expenditures through March 1987 and $796,900 in estimated additional costs to acquire the remainder of the HOTL right of way.

c. Line Losses

CAPE provided that the Company's 23 kV tie line and 23 kV feeder improvements would be an incorrect way to modify the system if the load were going to be supplied from existing substations, as under Alternative 1, rather than from Chatham substation, as under the proposal (Tr. 15, pp. 102-104). CAPE stated that these proposed improvements, centered on the Chatham substation site, would require power to travel longer distances from existing bulk substations to customers over 23 kV lines than under the existing distribution system, and thus is not a valid basis for calculating line losses under Alternative 1 (id., pp. 102-103, 116).

CAPE presented an alternate 23 kV configuration to the Company's proposed 23 kV tie line and 23 kV feeder line improvements (see Section III.D.2.b, supra), and asserted that the additional $2,541,051 of present value line losses estimated by the Company for Alternative 1, compared to the proposal, would be avoided under CAPE's suggested 23 kV configuration (Tr. 15, pp. 116-117; Tr. 16, pp. 104-107). However, CAPE provided no quantitative analyses to support its contention that a more favorable 23 kV configuration would allow Alternative 1 to be comparable to the proposal with respect to line losses.

The Company provided that, in the short run, line losses would be higher rather than lower under CAPE's configuration given CAPE's suggested use of 477 ACSR conductors (Tr. 17, pp. 146-149). Further, the Company stated that the load in Harwich and Chatham that is expected to be served by Chatham substation is not really confined to south of the 1/0 line (id., pp. 149-154).

The record shows that, under Alternative 1 with the Company's 23 kV tie and 23 kV feeder improvements, power indeed would need to travel a distance of about 6.5 to 7 miles from Harwich substation along 23 kV feeder lines--or about 1 to 3 miles farther than it would need to travel under CAPE's suggested alternate 23 kV configuration--in order to reach the various tap and distribution points located immediately along and south of the 1/0 line in South Harwich, South Chatham, and Chatham (Exhs. EFSC-8, EFSC-9). Considering the relative lengths of 23 kV lines between Harwich substation and the South Harwich and Chatham area under Alternative 1, CAPE's suggested 23 kV configuration may reduce the line losses under Alternative 1 with respect to load centered near or south of the 1/0 line through the South Harwich and Chatham area.

However, as analyzed by the Company, the line loss difference between the proposal and Alternative 1 reflects the utilization of approximately 5 miles of HOTL between Harwich substation and the proposed Chatham substation in order to serve the Chatham area load under the proposal, as opposed to the utilization of the 23 kV tie line as a feeder line along the same 5-mile segment in order to serve Chatham area load under Alternative 1 (Tr. 17, pp. 152-153). In essence, although overall 23 kV feeder line length is 1 to 3 miles less under CAPE's 23 kV configuration, any adjustment in relative line losses derived from CAPE's 23 kV configuration would be only a portion of the overall difference in line losses between the proposal and Alternative 1, as estimated by the Company. Further, in that (1) CAPE's 23 kV configuration may rely on smaller 477 ACSR conductors for a number of years and (2) under the Company's proposal, Chatham substation would serve some customers located well north of the 1/0 line, any adjustment for line losses may be even less than that suggested by a simple comparison of the overall lengths of 23 kV lines needed to serve areas along the 1/0 line.

In sum, the record provides an inadequate basis for the Siting Council either to determine a specific cost adjustment or conclude that the overall line loss difference between the proposal and Alternative 1 would be reduced significantly. Accordingly, the Siting Council finds that CAPE has not demonstrated that the 1987 total present value costs of Alternative 1 would be significantly lower than the levels estimated by the Company, taking into consideration additional line loss savings under the alternate 23 kV configuration suggested by CAPE.

5. <u>Conclusions on Cost Analysis of the Proposal and Alternatives</u>

The Company presented a 30-year present value cost analysis of the proposed and alternate facility plans, reflecting 30-year net present value revenue requirements and estimates of 30-year line loss differences between the proposal and certain alternatives. The Siting Council has found that the Company used an appropriate and reviewable general approach in compiling its analysis of costs of the proposal and alternatives.

In its review, the Siting Council also has considered a number of cost adjustments. With respect to major facilities, the Siting Council has found that (1) it is reasonable to assume that the Harwich A-C transformer would exceed its planned life and need to be replaced within the 30-year period used in the Company's analysis, and (2) as a result, the 1987 total present value cost of the proposal is $393,875 higher than the level estimated by the Company. The Siting Council also has found that (1) the Company could delay rebuilding the existing HT-H line under Alternative 1 from 1988 to 1991/92, and (2) as a result, the 1987 total present value cost of Alternative 1 is $134,725 lower than the level estimated by the Company.

With respect to the cost of the HOTL right of way and Chatham substation site, the Siting Council has found that the acquisition costs for the HOTL right of way and Chatham substation site are considered as part of the proposal but not Alternative 1. The Siting Council also has found that the Company's 30-year present value cost analysis is adjusted to reflect $2,085,741 in direct and indirect costs for acquisition of the HOTL right of way and the Chatham substation site under the proposal, including $1,288,841 in expenditures through March 1987 and $796,900 in estimated additional costs to acquire the remainder of the HOTL right of way.

With respect to line losses, the Siting Council has found that the 1987 total present present value costs of Alternative 1 would not be significantly lower than the levels estimated by the Company, taking into consideration additional line loss savings under the alternate 23 kV configuration suggested by CAPE.

Table 4 presents an overall comparison of 30-year total present value costs with the adjustments for costs of major facility elements and and HOTL right of way and Chatham substation site.

Table 4
Adjusted Total Present Value Costs,
1988-2017, Proposal and Alternative 1
($ millions)

	Total Present Value Cost	Adjustment Major Facility Element	Adjustment HOTL ROW and Chatham Substation Site	Adjusted Total Present Value Cost
Proposal	7.45	0.39	2.09	9.93
Alternative 1	11.42	(0.13)		11.29

Source: Exh. CAPE-6, Tab 97; Exh. EFSC-26A; Tr. 8, p. 76.

Based on these adjustments, Alternative 1 would be $1.36 million more costly than the proposal, as opposed to the nearly $4 million difference set forth in the Company's original analysis shown in Table 3.[37]

Accordingly, the Siting Council finds that the proposal is preferable to Alternative 1 with respect to cost.

37/ Under the Brewster substation alternative, the Company stated that it was reasonable to assume an acquisition cost of at least $500,000 for the Brewster substation site (Tr. 12, p. 43; Tr. 14, pp. 37-38). In addition, both of the adjustments for major facility elements shown in Table 4 would apply to the Brewster substation alternative. Thus, the $9.42 million total present value cost with line loss adjustment for the Brewster substation alternative, as shown in Table 3, would be changed to $10.18 million to reflect a net increase of $0.76 million for the above adjustments. Based on these adjustments, the adjusted total present value cost of the Brewster substation alternative would be greater than the proposal but less than that of Alternative 1, as shown in Table 4.

E. Environmental Analysis of the Proposal and Alternatives

During the proceeding, Commonwealth provided analyses of the expected environmental impacts of the proposal and alternatives and possible measures to mitigate such impacts (Exh. C-1, pp. 13-23; Exh. C-2, pp. 50-58; Exh. CAPE-2, Q.26; Exh. EFSC-3, Environmental Q.17, Q.18, Q.19; Exh. EFSC-13; Exh. EFSC-14).[38] In its review, the Siting Council first determines whether the proposal and Alternative 1 would be acceptable with respect to its expected environmental impacts. Boston Gas Company, EFSC 86-25A, pp. 26-31; Northeast Energy Associates, 16 DOMSC 335, 391-407 (1987).[39] The Siting Council then compares the proposal and Alternative 1 to determine which plan is preferable in terms of having a minimum impact on the environment (see Section III.A, supra).

1. Water and Land Environments

In this section, the Siting Council considers possible impacts of the proposal and Alternative 1 on water and land environments, including possible displacement or degradation of environmental resources.

The Company identified two principal impacts of the proposal and Alternative 1 that represent displacement of environmental

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38/ Innis asserts that the Siting Council is a state agency within the purview of the Massachusetts Environmental Policy Act ("MEPA"), G.L. c. 30, secs. 61-62H, and that Commonwealth must comply with the statutory and regulatory requirements of MEPA before the Siting Council acts on Commonwealth's petition (Innis Brief, pp. 16-18). However, the Siting Council notes that, pursuant to G.L. c. 164, sec. 69I, neither the Siting Council nor any person shall, in taking any action pursuant to G.L. c. 164, secs. 69I and 69J, be subjected to any provisions of G.L. c. 30, secs. 61-62H.

39/ Before approving proposed facilities, the Siting Council must determine that the proposed facilities are "consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." G.L. c. 164, sec. 69J.

resources--the placement of transmission structures in wetlands and the clearing of vegetation in portions of affected rights of way. The Company provided estimates of the number of structures to be placed in wetlands and the acres of wooded wetlands to be cleared (Exh. EFSC-3, Environmental Q.17). The Company provided general indications of the overall extent of woodlands to be cleared, including those in upland and wetland areas (id.).

The Company estimated that the following numbers of structures would be placed in wetlands or surrounding "buffer zone" areas[40] for new or rebuilt overhead lines along the affected rights of way: (1) about 19 structures under the proposal, including 12 structures along the HOTL right of way and six to eight structures along the HT-H right of way, and (2) about 19 structures under Alternative 1, including five structures along the DOTL right of way and 12 to 16 structures (for two lines) along the HT-H right of way (id.). Thus, based on the Company's estimates, the proposal and Alternative 1 would have comparable impacts on wetlands in terms of likely structure placements. The actual extent and significance of wetlands displacement would depend on final design specifications, including the number of structures to be placed directly in wetlands as opposed to in buffer zones, the size of structure pads, if any, and the requirements for permanent or temporary access roads, if any.[41]

The Company estimated that five acres of wooded wetlands would be

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40/ The Massachusetts Department of Environmental Quality Engineering uses the term "buffer zone" to identify land within 100 feet of the edge of a wetland or bank of a water body (Tr. 3, p. 70).

41/ The Company estimated that 25 percent of the structures would be placed directly in wetlands and 75 percent would be placed in buffer zones (Tr. 3, pp. 70-71; Tr. 17, pp. 135-137). When placing a structure in a wetland, the Company stated that the structure may be placed in a concrete pad or may be "direct-buried" (Tr. 3, pp. 72-75).

cleared for the new and expanded segments of the HOTL right of way (id.).[42] With respect to the HT-H and DOTL rights of way, the Company estimated that two acres of wooded wetlands would be cleared for the second HT-H line required under Alternative 1 (id).

With respect to overall clearing requirements, including upland as well as wetland areas, the proposal would require a cleared area of 95 feet in width along the full 10-mile length of the HOTL route (Exh. C-2, p. 36). While the Company did not estimate the acres of forest to be cleared for the HOTL route, the record shows that, along the new portion of the HOTL route between Flax Pond and Freeman's Way, most of the proposed 175-foot right of way now is forested (Exh. C-1, Appendix C-2). In addition, along the existing portion of the HOTL right of way between Freeman's Way and the DOTL right of way just south of Orleans substation, the Company would widen the existing right of way by acquiring and clearing an additional 85-foot width of predominantly forested land (id.; Exh. EFSC-3, Environmental Q.22b; Exh. EFSC-5, IR 1.18a, IR 1.18b). The Company stated that the proposed Chatham substation would require clearing one or two acres, and provided that a similar clearing requirement should be assumed for a new substation under the Brewster substation alternative (Exh. EFSC-3, Environmental Q.16).

Along part or all of the HT-H route between Flax Pond and Harwich tap--a distance of about four miles--the Company estimated that there is an uncleared portion of the right of way up to 35 feet in width

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42/ In order to build HOTL, the Company would need to utilize the full length of the HOTL right of way under the proposal, and a portion of the HOTL right of way under the underground/overhead alternative; but the Company would not need to utilize the HOTL right of way for any new 115 kV facilities under Alternative 1 or other alternatives limited to existing rights of way (see Section III.B, supra). Although the Company did state its intention to acquire the full length of the HOTL right of way to build the 23 kV tie line under all alternatives (Exh EFSC-2, Need Q.25b), the Siting Council does not support this use of the HOTL right of way (see Section I.C.2.b, supra). In fact, the Siting Council noted that the Company provided that necessary 23 kV improvements could be made along town and state roads (see Section I.C.2.b, supra).

(Tr. 5, pp. 80-82). Under Alternative 1, these wooded portions of the HT-H right of way would need to be cleared for a second HT-H line (id.). Clearing of the DOTL right of way would not be needed under Alternative 1.

With respect to additional environmental resources potentially subject to degradation, the Company identified surface water bodies, public water supplies, erosion-prone land, and wildlife concerns that may be affected by the proposal[43] or Alternative 1 (Exh. C-1, pp. 13-23, Appendix C-2; Exh. C-2, pp. 50-58; Exh. CAPE-2, Q.26). The HOTL route would traverse watershed land owned by the Town of Orleans and land zoned as a water resource protection district in Harwich (Exh. EFSC-6; Exh. C-6). The HOTL route would parallel Coys Brook in Harwich, crossing the brook twice, and also traverse Flax Pond and Eldredge Pond in Harwich (Tr. 3, pp. 78-79). Many of the wetland areas along the HOTL right of way are concentrated in the Coys Brook area, extending from near Flax Pond to the crossing of Queen Anne Road (id., Exh. C-3, pp. 2-3; Exh. C-1, Appendix C-2). The HT-H right of way, which would be utilized for the second HT-H line under Alternative 1, traverses Flax Pond and passes near water supply wells in Dennis (Exh. C-1, Appendix C-2; Exh. CAPE-2, Q.26).

The Company indicated that it has not used herbicides to maintain rights of way on Cape Cod since 1982 (Tr. 3, p. 82). The Company also stated that it would not chemically treat rights of way before a

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43/ Many of the potential impacts that the proposal would have on environmental resources could be partially avoided under the underground/overhead alternative, especially the three options providing for the longer underground segments along Queen Anne Road or Route 39 and bypassing most of Coys Brook and Eldredge Pond. However, the Company also indicated that underground construction would require placing conductors in a pipe and circulating oil through the pipe for cooling purposes (Exh. C-2, p. 41). While underground construction would occur primarily along streets, the underground segments under all the options would cross Coys Brook and traverse the water resource district in Harwich for a distance of more than a mile. Thus, in the event of an oil leak, there may be direct impacts on groundwater protected for water supply purposes or indirect impacts on any nearby wetlands or surface water bodies.

pending program for right of way maintenance is implemented by the Massachusetts Department of Food and Agriculture ("MDFA") (Exh. C-1, pp. 14-15; Exh. C-2, p. 55). In fact, in November, 1985, the Company stated that it had entered into a five-year agreement with a contractor for mowing system rights of way (Exh. EFSC-1, Right of Way Q.6).

Although the Company stated that it currently has no plans to use herbicides to maintain rights of way in the future (Exh. CAPE-4, Q.104, Q.106), CAPE asserts that the Company gave no assurances that it would not use herbicides along the HOTL right of way at some future time (CAPE Brief. p. 20). In the event that herbicide use is resumed along Company rights of way, its application could be expected to be proportional to cleared area and thus greatest under the proposal.

Based on information provided by the Massachusetts Natural Heritage Program, the Company indicated that regionally and nationally significant plant species had been sighted at certain ponds in the Lower Cape area (Exh. C-1, pp. 18-19). None of the identified ponds is traversed by the transmission line routes under either the proposal or Alternative 1 (id., Appendix C-2). The Company noted that no plant or animal species found along the HOTL route is designated by the Federal government as rare or endangered (id., pp. 17-18).

The Company stated that clearing of the HOTL right of way through wooded areas would benefit wildlife by creating "edge" habitat and by offering a more diverse food supply (Exh. C-2, p. 57). However, such habitats already exist along portions of the HOTL route, notably along the segment of existing right of way where only widening is proposed and in areas of overgrown bog and shrub swamp.

In sum, the proposal and Alternative 1 would have comparable impacts on wetlands. However, the proposal would require significantly more clearing of woods than Alternative 1. In the event the Company resumed use of herbicides in its Lower Cape rights of way, the proposal could result in greater use of herbicides than Alternative 1.

Overall, the Siting Council finds that the proposal and Alternative 1 are acceptable with respect to possible impacts on water and land environments. The Siting Council further finds that, on balance, Alternative 1 is preferable to the Company's proposal with respect to overall impacts on water and land environments.

2. Land Use and Development

In this section, the Siting Council considers possible impacts of the proposal and Alternative 1 on community land use and development, including any displacement of existing land uses through acquisition of new lands and easements for prospective facilities. In addition, the Siting Council considers the level of compatibility of prospective facilities with current land use and zoning in the surrounding area.

The Company expects to acquire new or expanded rights to 215.25 acres of land for the HOTL right of way (Exh. CAPE-2, IR 1.8). The Company already has acquired interests in 113.08 acres, and seeks to acquire interests in an additional 8.54 acres from known landowners and 93.63 acres from "owners unknown" (id.; Tr. 14, p. 86). No additional land would be acquired under Alternative 1.[44]

Intervenors provided no evidence that acquisition of the HOTL right of way would directly displace any existing developed land uses. However, a number of landowners have planned to subdivide or build upon their properties--actions that could be affected by acquisition of the HOTL route (Tr. 4, pp. 128-130, 187-188; Tr. 11, pp. 22-24, 36-37, 80-81, 135).

44/ In order to build new 115 kV transmission facilities, the Company would need to acquire the full length of the HOTL right of way under the proposal or Alternative 2, and a portion of the HOTL right of way under the underground/overhead alternative. The Company would not need to acquire any additional right of way for prospective new 115 kV facilities under the Brewster substation alternative or the double-end Orleans substation alternative. Although the Company did state its intention to acquire the full length of the HOTL right of way to build the 23 kV tie line under all alternatives (Exh EFSC-2, Need Q.25b), the Siting Council does not support this use of the HOTL right of way (see Section I.C.2.b, supra). In fact, the Siting Council noted that the Company provided that necessary 23 kV improvements could be made along town and state roads (see Section I.C.2.b, supra).

In selecting the HOTL route, the Company responded to DEM's position that HOTL be sited such as to minimize impacts on future use of Hawksnest State Park (see Section III.C.1.b.i, supra). Mr. Bliss stated that the landholding is particularly valuable, given the rate of new development on Cape Cod, and increasingly has been used for hunting, swimming and passive recreation (Tr. 11, pp. 180-182, 195-197). Mr. Bliss stated that the HOTL route would intrude less on the overall integrity of Hawksnest State Park than the originally proposed route through the park, but indicated his preference that HOTL not be built through the park at all (id., pp. 180-182). See Section III.C.1.b.i, supra.

In addition to requiring acquisition of rights to land now vacant or utilized for other purposes, development of the HOTL route could increase accessibility to private land along the route and thereby result in unauthorized use of abutting lands by people on foot or in all-terrain vehicles (Tr. 4, pp. 102-110; Tr. 11, pp. 19-20, 48, 81). CAPE and Innis argue that their concerns about increased noise, trespassing, vandalism, burglaries and other nuisances associated with unauthorized access are well-founded (CAPE Brief, p. 21; Innis Brief, p. 8).

The Company stated that it would cooperate with any landowner in controlling unauthorized access along the HOTL right of way by providing a gate and lock, if the landowner agreed to provide the additional fencing necessary to restrict passage across his property (Exh. C-2, p. 48; Tr. 4, pp. 188-190). Still, it is not clear that landowners affected by the HOTL right of way could maintain current use and enjoyment of their property without incurring some cost.

In addition to the HOTL right of way, a new site for the Chatham substation would be required under the Company's proposal. The

Company already has acquired a 13.9-acre site for the proposed Chatham substation (Exh. C-1, p. 6).[45]

In sum, considering the need for a new and expanded right of way to construct HOTL and a new site to construct Chatham substation, the proposal would have a substantially larger impact on land use and development than Alternative 1.

The Siting Council finds that the proposal and Alternative 1 are acceptable with respect to expected impacts on land use and development. However, the Siting Council further finds that Alternative 1 is preferable to the proposal with respect to overall impacts on land use and development.

3. Visual Impacts

In this section, the Siting Council considers possible visual impacts of the proposal and Alternative 1, including any new or increased visibility of facilities in abutting areas, as well as the relative sensitivity of abutting areas to any increased visibility of such facilities. Where new facilities would be sited adjacent to or in place of existing facilities, the Siting Council considers the incremental impact of the additional facilities as well as the

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45/ A site for the prospective Brewster substation has not been acquired or identified, although the Company provided an assessor's map of the South Brewster area with the Company's notations as to the acreage, assessed value, and development status of parcels that might warrant investigation (Exh. C-13; Tr. 17, pp. 184-189). The Company stated that the prospective second transformer at Orleans substation probably could be built on a two-acre site owned by the Company across the street from the existing transformer, now utilized by a garden supply company (Tr. 10, pp. 31, 69-70).

cumulative impact of all facilities on the particular route or site.[46]

The Company assessed the expected visual impacts of transmission facilities in seven major segments of the HOTL route, rating the impacts as "low", "medium" or "high" (Exh. EFSC-3, Environmental Q.18). The Company provided that visual impacts would be low for the two segments of the HOTL route where there are existing facilities, including segments from Harwich substation to Flax Pond and from Orleans substation to Freeman's Way (id.). Citing limited visibility and lack of sensitive viewsheds, the Company stated that visual impacts also would be low along two of the segments of the HOTL route involving new right of way, including segments from Flax Pond to Coys Brook and from Freeman's Way to Chatham substation (id.). However, the Company stated visual impacts would be low-to-moderate or higher at points in the remaining three segments, citing high visibility in the entire segment through the Coys Brook area and in parts of the segment from Route 124 through the Eldredge Pond crossing, while citing the extent of residential development in the segment east of Eldredge Pond to Chatham substation including the Hawksnest State Park area (id.).

The Company acknowledged that, in considering the overall HOTL

46/ The Company would (1) construct HOTL along the full length of the HOTL right of way under the proposal or Alternative 2, and along a portion of the HOTL right of way under the underground/overhead alternative, (2) rebuild the existing HT-H line under the proposal and all alternatives, and build the second HT-H line adjacent to the HT-H line under Alternative 1, the Brewster substation alternative and the double-end Orleans alternative, and (3) rebuild DOTL 1 adjacent to DOTL 2 under Alternative 1, Brewster substation alternative and double-end Orleans substation alternative, but remove DOTL 1 under the proposal, Alternative 2 and the underground/overhead alternative (see Section III.B, supra). Although the Company did state its intention to acquire the full length of the HOTL right of way to build the 23 kV tie line under all alternatives (Exh. EFSC-2, Need Q.25b), the Siting Council does not support this use of the HOTL right of way (see Section I.C.2.b, supra). In fact, the Company provided that necessary 23 kV improvements could be made along town and state roads (see Section I.C.2.b, supra).

route, there would be both direct views of HOTL and partial views of such facilities through the trees from residences at some locations (Tr. 3, p. 107). With respect to the proposed pond crossings, the Company noted that there are a few residences and private boat landings on Flax Pond, as well as four to five residences and a private boat landing at Eldredge Pond (id., pp. 30-32).[47] In the vicinity of Coys Brook, where the HOTL route would cross the stream twice and extend along a bordering upland owned by the Clarks, the Company indicated that the visual impact of HOTL would be the highest due to the topography and the predominant swamp and bog vegetation (Exh. EFSC-3, Environmental Q.18; Tr. 3, pp. 79-81, 98-100). The Company stated that the HOTL route also would cross a bicycle trail owned by DEM, east of the Flax Pond area (Tr. 14, pp. 72-74).

In the vicinity of Hawksnest State Park, the Company provided that vegetative screening would limit the visibility of HOTL to a substantial degree from residences along the southern boundary of the park (Tr. 3, pp. 91-94, Tr. 4, pp. 58-62). However, CAPE and Innis argue that the buffer zone between the residences and the southern edge of the right of way through the park would be well under 100 feet wide in places, and would not be effective in screening views of HOTL (CAPE Brief, pp. 19-20; Innis Brief, pp. 2-3).

The Company provided the results of two surveys it conducted, including counts of the number of existing residences estimated to be within 100 feet of the HOTL, HT-H and DOTL rights of way (Exhs. EFSC-3, Environmental Q.19, EFSC-13). Based on the comparitive survey of all three rights of way, there would be 26 residences within 100 feet of the HOTL right of way, compared with 28 residences within 100 feet of the HT-H right of way and 135 residences within 100 feet of

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47/ In connection with the acquisition of a right of way across Ovaska's property on the southwest shore of Eldredge Pond, the Company paid $50,000 in consequential damages primarily to compensate for loss of a beach otherwise accessible from abutting lands (Tr. 4, pp. 187-188). However, the Company acknowledged that the consequential damages also may have related to the visual impact of HOTL crossing the pond (id., p. 188).

the DOTL right of way (Exh. EFSC-13). The Company stated that most of the residences within 100 feet of the DOTL right of way were built in the last 10 to 12 years, well after the Company installed DOTL 1 (Tr. 12, pp. 119-123).

The Company contends that, in comparing the visual impacts of the proposal and Alternative 1, the Siting Council should determine the ultimate visual impacts along each affected right of way (Company Brief, p. 42). With respect to Alternative 1, the Company argues that building the second HT-H line would cause an incremental visual impact (Company Reply Brief, pp. 9-10). In addition, Commonwealth argues that rebuilding DOTL 1 under Alternative 1 also should be viewed as creating an incremental visual impact because the eventual removal of DOTL 1 had been envisioned when the Siting Council approved construction of DOTL 2 in Commonwealth Electric Company, 6 DOMSC 33, 41 (1981) (id.). The Company asserts that more homeowners would be affected by the visual impacts of Alternative 1, as compared with the number of homeowners that would be affected by HOTL under the proposal (id., p. 10).

CAPE asserts that there is a qualitative difference between the replacement of an old set of transmission towers and wires with a new line, and the creation of a whole new transmission corridor (CAPE Reply Brief, p. 7). CAPE maintains that a simple comparison of residence counts along the HOTL and DOTL rights of way ignores the fact that most of the homes near the DOTL right of way were constructed well after DOTL 1 had been built there (id.). With respect to the HT-H right of way, CAPE argues that it may be possible to put the second HT-H line on the same set of poles as the rebuilt existing HT-H line, and that in any case the incremental impact of a second set of towers and wires on that route would not be significant (id.).

Based on the record, it is clear that HOTL would result in significant visual impacts along portions of the HOTL route, particularly from Coys Brook to Eldredge Pond and in the Hawksnest State Park area. In addition, despite the presence of existing transmission lines, visual impacts also may be significant in the Flax

Pond area, where HOTL would pass within 60 feet of a residence on the south shore and extend along new right of way near the north shore of the pond.

We note however, that the two ponds traversed by the HOTL route cannot be considered as being extensively used for residential or recreational purposes. Further, in the approximate five miles between the proposed Chatham substation and the intersection with the DOTL right of way, the HOTL route would pass near the Mid-Cape Highway (Route 6) at one point but otherwise extend through relatively isolated wooded areas with very limited residential impact (Exh. EFSC-13).

With respect to the relative visual impacts, however, the incremental visual impacts of the rebuilt DOTL 1 and existing HT-H line and the second HT-H line under Alternative 1, clearly would be less than those incremental visual impacts of HOTL on the HOTL right of way. The rebuilt DOTL 1 would be taller than the old DOTL 1, but could result in a more compatible appearance on the right of way compared to that of the existing H-frame structures of the old DOLT 1 (Exh. C-1, p. 21). More importantly, the rebuilt DOTL 1 would be no taller than the adjacent DOTL 2, and would be nearer the center of the right of way than DOTL 2. Likewise, the second HT-H line, which the Company would build under Alternative 1, would be of comparable height to the rebuilt existing HT-H line under the proposal and Alternative 1.

With respect to the prospective second HT-H line under Alternative 1, the Siting Council previously has found that "use of an existing right of way as the site of new lines is the most appropriate way to achieve the proper statutory balance..." and that the environmental impact of such use is "prima facie minimal". Boston Edison Company, 3 DOMSC 44, 53-54, 61 (1978). In this case, use of an existing right of way, as opposed to a new right of way, minimizes the incremental visual impact of transmission facilities.

In regard to the Chatham substation contained in the proposal, the Company stated that the new Chatham substation would have a road screen, with an angular entry, to prevent the substation from being visible from the road (Exh. C-2, p. 33). Thus, the visual impact of the Chatham substation under the proposal would be minimal.

In sum, considering the incremental visual impact of constructing HOTL on a new right of way, the proposal would have a greater visual impact than Alternative 1.

The Siting Council finds that the proposal and Alternative 1 are acceptable with respect to expected visual impacts. However, the Siting Council finds that Alternative 1 is preferable to the proposal with respect to visual impacts.

4. Electrical Effects

Electrical effects of transmission lines include possible effects of electric fields and magnetic fields on humans or on biological resources.[48]

The Company provided that, based on available research, the potential for health hazards from a 115 kV transmission line is negligible or non-discernible (Exh. C-2, p. 58). The Company stated that, in comparing the proposed and alternate facility plans with respect to possible effects on health, there is no basis in available research for the Company to posit that one plan is preferable to another (Tr. 17, p. 133).

In support of its position concerning health effects, the Company analyzed levels of electric field that would be expected near the ground beneath a 115 kV line and extending out to distances up to 70

48/ The range of possible effects on humans and biological resources includes those that have been known to occur in certain situation(s) involving electrical transmission (for example, shock, effects on pacemakers, effects on honey production by bees), and other potential effects that have been hypothesized and/or investigated but are not generally accepted as known or proven effects of electrical transmission (for example, effects on milk production by cows, headaches or other perceivable discomforts or symptoms in humans, reproductive disorders and chronic effects such as cancer in animals or humans). In its review of the Hydro Quebec project, which included 450 kV direct current and 345 kV alternating current transmission facilities, the Siting Council addressed in detail the expected electrical effects of such facilities, notably the health implications of electric and magnetic fields. See Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985).

feet from the centerline (Exh. EFSC-14). The results of the Company's analysis indicate that, at the mid-point of the span between transmission structures, the maximum electric field beneath the lines would be 1.003 kV per meter ("kV/m"), decreasing to 0.416 kV/m and 0.166 kV/m at distances of 30 feet and 60 feet, respectively, extending away from the centerline on the side with one conductor (id.). Neither the Company nor the intervenors provided any evidence regarding the relative electrical effects, if any, for the proposal and Alternative 1.[49]

As an indication of how these data might relate to HOTL's alignment along the HOTL route, the Company stated that the nearest right of way edge would be 35 feet from the proposed centerline and the nearest residence would be approximately 60 feet from the proposed centerline (Tr. 10, pp. 73-75).[50]

Innis argues that HOTL would expose him, his family and his neighbors to a substantially heightened fear of cancer and other

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49/ In the review of a radial 115 kV line proposed in a built-up area in Hingham, the petitioner compared the general level of magnetic field that would be produced by such a 115 kV line with the level of magnetic field that would be produced by a 345 kV line such as the one reviewed in the Hydro Quebec case, assuming an end-of-line transformer load of 40 MW for the 115 kV line and a line load of 1,000 MVA for the 345 kV line. Hingham Municipal Lighting Plant, 14 DOMSC 7, 19-20 (1986).

50/ Based on single-pole davit arm construction with two conductors on one side of the pole and one conductor on the other side, the field levels at various distances from the centerline are not symmetrical with respect to side. Maximum electric field would occur 17 feet from the centerline on the side with two conductors, while the field at a distance of 60 feet from the centerline on that side would be 0.211 kV/m, as compared with 0.166 kV/m on the other side (Exh. EFSC-14).

adverse biological effects of electromagnetic radiation (Innis Brief, p. 3).[51] Innis provided a copy of a report "Biological Effects of Power Line Fields", prepared as part of the New York State Powerlines Project ("Powerlines Project Report"), and also referred to a letter to the Company from Dr. Carpenter, Executive Director of the New York State Powerlines Project (Exh. Bliss-11; Exh. C-12). Innis argues that Dr. Carpenter, while recognizing that cause-and-effect relationships had not been established, had advised the Company that a recent study by a Dr. Savitz, included in the Powerlines Project Report, significantly strengthens the hypothesis that electromagnetic fields cause cancer (Innis Brief, p. 5).

The Company stated that no studies included in the Powerlines Project Report show a definite cause-and-effect relationship between magnetic fields and increased incidence of cancer (Tr. 17, pp. 122-125). CAPE argues that, although the evidence placed in the record as to the long-term effects of power line fields is inconclusive, harmful effects cannot be ruled out by the Company (CAPE Brief, p. 21).

In its review of the Hydro Quebec project, which included 450-kV direct current and 345-kV alternating current transmission facilities, the Siting Council addressed in detail the expected electrical effects of such facilities, notably the health implications of electric and magnetic fields. Massachusetts Electric Company, 13 DOMSC 119, 228-242 (1985). In that case, the petitioner estimated that electric field would not exceed 1.8 kV/m and that magnetic field would not exceed 85 milligauss along the edge of the 345 kV rights of way. Id., pp. 228-229. The Siting Council accepted those edge-of-right-of-way field levels. Id., p. 241.

51/ Innis requested that the Company not place HOTL as close to his residence on Beach Plum Circle as proposed (Innis Brief, p. 15). The Company responded to this request by proposing to move the HOTL alignment to the north side of the HOTL right of way (Company Brief, p. 21). Assuming the HOTL and the 23 kV tie line are within a 95-foot cleared zone on the north side of the right of way through that area, they would be over 125 feet from the rear property lines along Beach Plum Circle and Quails Nest Run.

In the current review, the expected levels of electric field under HOTL, and at the edge of the HOTL right of way, are well below the levels accepted by the Siting Council after detailed review of the Hydro Quebec project. The expected magnetic field levels under HOTL and at the edge of the HOTL right of way were not estimated by the Company in this proceeding.[52] Finally, neither the Company nor the intervenors provided any evidence regarding the relative electrical effects, if any, for the proposal and Alternative 1.

The Siting Council finds that the proposal and Alternative 1 are acceptable, and that there is no preference between the proposal and Alternative 1 with respect to electrical effects.

5. Noise Impacts

The Company indicated that audible noise produced by overhead transmission lines primarily is a foul-weather phenomenon (Exh. C-1, p. 22). The Company stated that noise levels generally do not exceed those normally found in the home unless voltages are in excess of 500 kV, and in any case can be minimized through good construction practices (id.).

The Company provided that increases in noise in areas surrounding the Chatham substation would be less that the 10-decibel limit set by state regulation (Exh. EFSC-2, Environmental Q.15; Tr. 3, p. 48). The Company noted that, with increased energy costs, it is often cost-effective to use low-noise transformers because such transformers also are more efficient with respect to substation energy losses (Tr. 12, pp. 29-31). The Company stated that it also had switched from oil circuit breakers to quieter vacuum or gas circuit breakers (id., p. 30).

The Company acknowledged that a noise increase of 10-decibels at

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52/ In the Siting Council's review of a 115 kV transmission project in Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985), the petitioner estimated that magnetic fields would be well below the edge-of-right-of-way level of 85 milligauss accepted by the Siting Council in the Hydro Quebec case.

a nearby home likely would be perceptible to the occupants (Tr. 3, p. 53). However, the Company provided that a noise increase of 5 decibels would not be perceptible to nearby residents (id., pp. 50-53). The Company indicated that, in selecting a transformer, it considers the surrounding land use and favors a quieter transformer if residences are nearby (Tr. 12, p. 36).

In comparing the noise impacts of the proposal and Alternative 1, the Company acknowledges in its brief that an upgrade of the Harwich A-C transformer under Alternative 1 would have less noise impact than the Chatham substation (Company Brief, p. 40). It is indeed likely that the upgraded Harwich A-C transformer would result in a smaller noise increase than Chatham substation, or result in no noise increase, given that transformers currently are in operation at the Harwich substation site.

The Siting Council finds that the proposal and Alternative 1 are acceptable with respect to noise impacts. However, the Siting Council finds that Alternative 1 is slightly preferable to the proposal with respect to noise impacts.

5. Conclusions on Environmental Analysis of the Proposal and Alternatives

The Siting Council finds that the proposal and Alternative 1 would have an acceptable impact on all of the environmental concerns raised in this proceeding.

The Siting Council has found that (1) Alternative 1 is preferable to the proposal with respect to impacts on water and land environments, (2) Alternative 1 is preferable to the proposal with respect to impacts on land use and development, (3) Alternative 1 is preferable to the proposal with respect to visual impacts, (4) Alternative 1 is slightly preferable to the proposal with respect to noise impacts, and (5) there is no preference between the proposal and Alternative 1 with respect to electrical effects.

Accordingly, the Siting Council finds that Alternative 1 is preferable to the proposal with respect to environmental impacts.

F. Reliability Analysis of the Proposal and Alternatives

During the course of the proceeding, the Company presented its position concerning system reliability under the proposal and alternatives, together with analyses such as load projections and load flow studies (Exh. C-2, pp. 13-23; Exh. EFSC-1, Need Q.7; Exh. EFSC-2, Need Q.16; Exh. EFSC-18; Exh. CAPE-5, Q.82, pp. 103-108; Exh. CAPE-7, Q.126, Q.127). As part of its review of reliability, the Siting Council evaluates the proposal and Alternative 1 in terms of (1) system reliability, (2) sensitivity to future load change, and (3) lead-time requirements for site acquisition and licensing.

1. System Reliability

The Company has indicated that, while the reliability of the proposal and the alternatives is not the same, the proposed and alternate facility plans all meet the basic criteria identified by the Company (Exh. EFSC-2, Need Q.16) (see Section II.A.3.a, supra).

The Company stated that Alternative 1 is less reliable than the proposal because it requires the Company to use common rights of way for two 115 kV transmission lines along both the HT-H and DOTL routes (Exh. EFSC-2, Need Q.16; Exh. CAPE-4, Q.115). The Company further stated that Alternative 1 and other alternatives that do not include the proposed Chatham substation are less efficient than the proposal because power would be carried longer distances over distribution lines, resulting in higher line losses and reduced voltage levels (Exh. EFSC-2, Need Q.16). Finally, the Company stated that the proposal would provide for a more even supply of power from the transmission system to the distribution system, enhancing the flexibility of the overall system to supply load (Exh. CAPE-7, Q.127; Tr. 8, pp. 23-27).

In support of its position regarding the reliability of two lines on the same right of way under Alternative 1, the Company stated that a neighboring utility had experienced ten simultaneous outages of high voltage lines on common rights of way attributable to single localized weather events or accidents during the years 1976 to 1981 (Exh.

CAPE-7, Q.126). With respect to voltage levels, Table 5 sets forth the minimum voltage levels for 1990 summer peak load in Chatham for the proposal and Alternative 1.

Table 5
Summer Peak Load Voltage in Chatham
Proposal and Alternative 1

	Normal Operation	Contingency of Harwich A-C Outage	Contingency of Orleans Outage
Proposal	1.027	1.024	1.020
Alternative 1	1.014	.989	.978

Source: Exh. CAPE-5, Q.82, pp. 103-108.

The Company stated that minimum voltage levels under the Brewster substation alternative would be somewhere between the minimum voltage levels for the proposal and Alternative 1 (Tr. 9, pp. 104-105).

CAPE asserts that the possibility of simultaneous loss of dual 115 kV lines on the DOTL or HT-H rights of way is not a significant reliability concern (CAPE Brief, p. 12). Mr. Kusko, citing generic data, testified that the incidence per mile of line per year of mechanical failures simultaneously affecting two adjacent high-voltage circuits on a common right of way is about one-fifth the incidence of mechanical failures affecting a single circuit on a right of way (Tr. 15, pp. 95-97; Tr. 16, pp. 5-8).[53]

In addition, CAPE stated that its preferred plan--consisting of Alternative 1 and CAPE's alternate 23 kV system configuration--would provide adequate voltage support in the Chatham area for the relevant 10-year planning period and beyond (Tr. 16, p. 13). CAPE also stated that Chatham substation would not be needed to provide operational

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53/ Mechanical failures, referring to collisions of vehicles, aircraft or similar objects with transmission lines, account for only about one-tenth of total failures (lightning and storm damage account for most failures); the incidence of mechanical failures on single circuit lines is reported as about one failure per 10 miles per 10 years (Tr. 16, pp. 5-6).

flexibility or back-up capacity in the Chatham area (id.; Tr. 15, p. 89).

Referring to the Company's own estimates of future substation loadings and 23 kV system power flows, Mr. Kusko testified that the so-called "Chatham load center" would provide only one-third of the load in the larger subject area under review, extending generally between Harwich and Orleans substations (Tr. 15, pp. 53-59; Tr. 16, pp. 118-119). Mr. Sylver, a Chatham area contractor and member of CAPE, testified that building activity in Chatham has slowed substantially in the last 6 to 12 months, citing zoning changes and land use saturation as causes (Tr. 11, pp. 84-92, 136).

The generic data on outage frequency provided by CAPE do not refute the Company's position that use of common rights of way would increase the probability of a simultaneous loss of two 115 kV lines feeding a substation. Nevertheless, the risk of such simultaneous outages is characterized by NEPOOL as "possible but improbable" (Exh. CAPE-2, IR 1.23, p. 8). Further, the Siting Council has previously found that, under its overall standard of review, use of existing rights of way for new transmission lines is the most appropriate way to achieve the "proper statutory balance." Massachusetts Electric Company, 13 DOMSC 119, 191-192 (1985). Boston Edison Company, 3 DOMSC 44, 53-54, 61 (1978).

With respect to voltage support, the proposal provides higher voltage levels on the distribution system than Alternative 1 or the other alternatives. Yet, the record provides no indication that, based on these voltage differences, any of these alternatives would provide inadequate 115 kV transmission or bulk substation capacity to ensure reliable supply for the Lower Cape.

The significance of the voltage differences for the future adequacy of the 23 kV system under the proposal and the alternatives is less clear. While the Company identified a common set of 23 kV improvements to meet its forseeable needs under the proposal and all alternatives, the Company indicated that future expansion of the 23 kV system must be considered dynamic--that is, subject to change based on the locations and timing of future growth (Tr. 6, pp. 15-18). In addition, the Company appeared to suggest that additional 23 kV improvements beyond those proposed might be required within 30 years, and that such improvements might be needed sooner under various alternatives than under the proposal (id.; Tr. 8, pp. 84-90).

The voltage difference between the proposal and Alternative 1 must be viewed as potentially significant in the Company's planning for the 23 kV system. However, there is no indication in the record that, based on voltage differences between the proposal and Alternative 1, further 23 kV improvements beyond those already proposed would be required within the Siting Council's normal 10-year forecast horizon.[54]

With respect to flexibility of the overall system, the Company did not provide any quantitative indicators of differences in reliability. However, the Company provided that the relative ability to respond to low-voltage system outages can be affected by the extent of low-voltage line exposure, including the lengths of feeder lines and the degree of looping in the distribution system (Tr. 8, pp. 23-27; Tr. 14, pp. 107-110).

In sum, the Siting Council finds that there would be system reliability differences under the proposal and Alternative 1 relating to (1) relative risk of simultaneous 115 kV line outages, (2) relative flexibility of overall distribution, and (3) in the long run, depending on future load growth, relative voltage levels. The Siting Council further finds, with respect to system reliability, that the Company's proposal is preferable to Alternative 1.

2. Future Load Change

The Siting Council also compares the various facility plans in terms of their relationship to possible load change. In particular,

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54/ With respect to the Brewster substation alternative, which would result in minimum voltage levels somewhere between the voltage levels of the proposal and Alternative 1 (Tr. 9, pp. 104-105), the Company did not expect any need for additional 23 kV improvements to arise for close to 20 years (Tr. 8, pp. 87-88).

the Siting Council considers the sensitivity of the Company's analyses of need, cost and environmental impact to possible variations in future load change.

As previously discussed, the Company's analyses of system reliability and line losses were based on the forecast of non-coincidental peak divisional load contained in the Company's most recently approved forecast, as allocated to the bulk substation level (see Section II.A.3.a, supra). However, the Company also provided load projections at the divisional and substation levels for a high-range growth scenario, based on the upper bound of a bandwidth probabalistic forecast prepared as part of the most recent forecast filing with the Siting Council (Exh. EFSC-18; Tr. 13, pp. 19-21). The Company indicated that it has developed its bandwidth forecast to represent the range of possible future load growth the Company expects with a 95 percent level of confidence, considering possible variations in such factors as demographic change, economic change and price of electricity (id.). Table 6 shows the upper-bound possible future substation loadings in the Lower Cape area for 1995 and 2017 based on the bandwidth forecast.

Table 6
Future Summer Peak Load at Lower Cape Substations
Based on High-Range Forecast (MW)

Substation	1995	2017
Harwich GE	44.1	72.3
Harwich AC	38.9	63.0
Orleans	37.7	61.9
Wellfleet GE	14.0	24.4
Wellfleet Mol.	34.6	59.6
Total	168.3	281.2

Source: Exh. EFSC-18.

The Company stated that the proposed facility plan could support a load of up to 180 MW in the area of the Lower Cape (Exh. EFSC-3, Need Q.34a; Tr. 14, pp. 115-117). The Company provided that a 180 MW capability would be adequate for the Lower Cape area through 2015 (Tr. 14, pp. 116-117). Yet, Table 6 indicates that the 180 MW limit could be exceeded by more than 50 percent in 2017, under the upper bound of the Company's bandwidth forecast.

With respect to substation capacity, the Company stated that the proposed facility plan would leave the Company with the option of later upgrading the Harwich A-C transformer if still more capacity is needed in the future--an option that would no longer be available under Alternative 1 (Tr. 9, pp. 46-47). In regard to transmission capacity, the Company stated that the HOTL right of way provides space for an additional 115 kV line should one eventually be needed, and that the Company may continue to acquire the full 175-foot HOTL right of way for reserve purposes even if HOTL is not approved (id., pp. 114-115).[55]

Clearly, acquiring a new substation site now would provide the Company with more flexibility to expand substation capacity later without the necessity of finding and developing a future site. The Company's proposal, as well as either the Brewster substation alternative or the underground/overhead alternative, would provide some reliability advantage over Alternative 1, which does not incorporate a new substation site now. However, based on the emergency substation ratings provided by the Company, Alternative 1 incorporates a Lower Cape substation capability in 2017 that, at least in aggregate, is not significantly exceeded by the Company's high-range load growth scenario (Exh. CAPE-2, Q.14).

With respect to transmission, extra right of way space for a possible additional 115 kV line indeed would be available under the proposal, not only along the HOTL right of way but also along the DOTL and HT-H rights of way. However, based on the normal and emergency operating capabilities of the 115 kV conductor size the Company expects to utilize, Alternative 1 would provide 115 kV transmission capacity that significantly exceeds the 180 MW Lower Cape load on

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55/ Commonwealth acknowledged that, in the event it proceeded to install the a 23 kV tie line along the HOTL right of way, the Company would not require the full use of the 175-foot right of way (Tr. 14, pp. 113-114).

which the Company's reliability analysis is based.[56] Thus, there is no identifiable need for any reserve right of way space under Alternative 1, even assuming the high-range load growth scenario.

Accordingly, the Siting Council finds that the proposal and Alternative 1 are comparable with respect to the ability to meet future load including that under the contingency of a high-range load growth scenario.

3. Site Acquisition and Licensing

Finally, the Siting Council analyzes the ability of the Company to ensure reliability of supply in a timely manner. In particular, the Siting Council considers the ability of the Company to acquire necessary permits and rights to implement the proposal and alternative facility plans.

Three of the facility plans--the proposal, Alternative 2 and the underground/overhead alternative--would require acquisition of new rights of way, while a fourth facility plan--the Brewster substation alternative--would require acquisition of a new substation site.

56/ The Company indicated that new and rebuilt 115 kV lines under all the facility plans would have a summer short-term emergency rating of 1301 amperes, or approximately 150 MVA (Exh. C-1, p. 9; Exh. CAPE-2, Q.14). Alternative 1 provides for two double-radial 115 kV lines originating at Harwich tap, with each line serving only a portion of the Lower Cape bulk substations and their associated load. In contrast, the proposal involves a single 115 kV circuit originating at and returning to Harwich tap in a loop configuration, with that one line serving all the Lower Cape bulk substations and their associated load. Thus, the proposal results in a more severe long-term 115 kV transmission constraint than Alternative 1 because, in the event of a fault along either the DOTL or HT-H portions of a single-circuit loop beginning at and returning to Harwich tap, there must be adequate single-line capability to serve all the Lower Cape bulk substations along the closed side of the loop. Such a transmission constraint, although apparently not a concern under any facility plan up to the 180 MW limit cited by the Company, could become a factor under the proposal if load surpasses 180 MW. However, Alternative 1, which effectively splits the Lower Cape load between two double radial lines, appears adequate for meeting the overall Lower Cape load beyond the 180 MW limit.

Implementation of Alternative 1 or the double-end Orleans substation alternative would require no additional rights. As described below, the various facility plans also could differ as to the overall extent of regulatory review, including environmental permit reviews and eminent domain proceedings.

With respect to the ability of the Company to implement the proposed facility plan in a timely fashion, the Company acknowledged that it no longer is realistic to assume the 1988 on-line date reflected in the Company's analysis (Exh. EFSC-1, Need Q.7; Tr. 12, p. 45). The Company estimated that eminent domain proceedings at the Massachusetts Department of Public Utilities--a step the Company expects to take in order to complete acquisition of the HOTL right of way--could take about one year (Tr. 12, p. 46). The Company estimated that environmental permitting would take at least 18 months, and if an Environmental Impact Report ("EIR") is required, as much as 30 months, but suggested that environmental review could proceed contemporaneously with any eminent domain proceedings (id., pp. 46-48). Thus, assuming that an EIR is required, the Company stated that it expects construction of the proposal could begin about 30 months after a Siting Council decision (id., p. 48). The Company stated that construction would take 10 to 12 months, indicating that the proposal would not be on-line until sometime in 1991 (id., pp. 48-49).

The Company stated that it expects Alternative 1 and the other alternative facility plans would require similar lead times (id., p. 49). With respect to the Brewster substation alternative, however, the Company provided that it could need one month to as much as three or four years in order to acquire a substation site, including a search and negotiations for one or more parcels in a suitable location (Tr. 14, pp. 38-39).

The Company noted that construction permits are needed for wetland and waterway crossings (Tr. 3, pp. 45-46). As the proposal and Alternative 1 have comparable wetlands impacts and each crosses at least one pond, the time required to obtain these construction permits may indeed be comparable.

However, the Company was uncertain about its expectations as to the likely scope and complexity of any required EIR review under the proposed or alternative facility plans, declining to rule out the possibility that a variety of concerns such as electrical effects, herbicides usage and visual impacts might have to be addressed (id., pp. 46-47). In addition, the Company acknowledged that there is uncertainty as to the nature and extent of the eminent domain proceedings, and any possible related litigation in the courts, that the Company expects would be necessary to fully acquire the HOTL right of way (Tr. 4, pp. 96-97, 133-135; Tr. 9, pp. 43-48; Tr. 12, pp. 45-46, 154-157).[57]

In sum, the proposal and the alternatives cannot be implemented in 1988, as assumed in the Company's analyses of cost and system reliability, and may require an implementation lead time of 30 months or more prior to commencement of construction. Further, the facility plans that would utilize part or all of the HOTL right of way (the proposal, Alternative 2 and the underground/overhead alternative) and the Brewster substation alternative would be more vulnerable to possible delays in implementation prior to commencing construction than Alternative 1, which would not require the acquisition of any new right of way or a new substation site. Accordingly, the Siting Council finds that Alternative 1 is preferable to the proposal with respect to site acquisition and licensing.

4. Conclusions on Reliability Analysis of the Proposal and Alternatives

The Siting Council has found that (1) the proposal is preferable

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57/ In the event of a delay in implementing 115 kV improvements, the Company may be able to begin implementing some or all of the needed 23 kV improvements with a shorter lead time. In particular, installing on-street feeder lines generally does not require eminent domain proceedings, although town approvals for use of public ways could be required. Likewise, EIR and environmental permitting requirements may differ for 23 kV improvements, particularly if built along streets or on rights of way where no high voltage improvements are planned.

to Alternative 1 with respect to system reliability, (2) the proposal and Alternative 1 are comparable with respect to meeting future load growth including that under the contingency of a high-range load growth scenario, and (3) Alternative 1 is preferable to the proposal with respect to for site acquisition and licensing.

In balancing the reliability advantages of the various facility plans, it is necessary to distinguish between a 10-year period of analysis typically used in Siting Council reviews, and the 30-year period used for some of the analyses in this proceeding.

Within the 10-year time frame, sensitivity to high-range load growth is not a critical factor because the proposed and alternate facility plans have been designed for a 30-year time frame. During the 10-year period, system reliability is a factor primarily with respect to risk of simultaneous outage of two 115 kV lines on a common right of way and flexibility of supply in the distribution system. Voltage constraints, which are more dependent on load growth, do not become an important factor until after 10 years. Implementation lead time, however, is of maximum significance in the first 10 years. Accordingly, the Siting Council finds that Alternative 1, which the Siting Council found to be preferable with respect to site acquisition and licensing, is preferable with respect to overall reliability in the 10-year time frame.

However, over the 30-year life of the facilities addressed in this review, system reliability concerns such as voltage differences and flexibility of supply become potentially more significant than in the initial 10-year period. In this longer-term context, the proposal offers additional system reliability advantages over Alternative 1 that must be weighed against the advantages of Alternative 1 over the proposal with respect to implementation lead time.

Overall, the Siting Council finds that the proposal and Alternative 1 are comparable with respect to reliability.

G. Conclusions on Analysis of the Proposed Facilities

With respect to the Company site selection process, the Siting Council has found that the Company developed and applied a reasonable set of criteria for identifying possible overall transmission configurations. The Siting Council also has found that the Company considered a reasonable range of practical facility siting alternatives including the Company's alternatives and the alternatives suggested by the intervenors and the Siting Council staff.

The Siting Council has found that (1) on the basis of cost, the Company's proposal is preferable to Alternative 1, (2) on the basis of environmental impacts, Alternative 1 is preferable to the Company's proposal, and (3) on the basis of reliability, the Company's proposal and Alternative 1 are comparable.

The Company's proposal includes approximately 10 miles of construction of HOTL along the HOTL right of way, of which approximately 6.5 miles involves clearing entirely new right of way. The record in this proceeding has demonstrated that the Company's proposal has significant environmental impacts with respect to water and land environments, and land use and development. In addition, the Company's proposal has significant visual impacts. The environmental impacts of Alternative 1, which utilizes existing rights of way, are less substantial. While the Siting Council recognizes the cost difference between the proposal and Alternative 1, the Siting Council has consistently stated its preference for the use of existing rights of way. Massachusetts Electric Company, 13 DOMSC 119, 191-192 (1985); Boston Edison Company, 3 DOMSC 44, 53-55, 61-64 (1978). Therefore, the Siting Council finds that the environmental advantages of Alternative 1 significantly outweigh the cost advantages of the Company's proposal.[58]

58/ In Boston Edison Company, 3 DOMSC 44, 51-55, 68 (1978), the Siting Council approved an alternative route which utilized an existing right of way based on the environmental advantages of the alternative outweighing the cost advantages of the Company's proposed route.

Accordingly, the Siting Council finds that Alternative 1 is superior to the Company's proposal.

IV. DECISION AND ORDER

The Siting Council finds that construction of the facility along the Harwich tap to Harwich substation route described herein is consistent with providing a necessary energy supply with a minimum impact on the environment at the lowest possible cost. The Siting Council further finds that the facility is consistent with the Company's most recently approved forecast in Commonwealth Electric Company, 15 DOMSC 125 (1986).

Accordingly, the Siting Council hereby APPROVES the petition of the Commonwealth Electric Company to construct a 4.5-mile, 115 kilovolt transmission line from Harwich tap to Harwich substation included as part of Alternative 1 contained in the Occasional Supplement, subject to the following CONDITION:

> In accordance with Administrative Bulletin 78-2, Commonwealth shall provide a typical cross-section sketch or sketches showing the Harwich tap to Harwich substation right of way as it would appear prior to and after construction of the 4.5-mile, 115 kilovolt transmission line from Harwich tap to Harwich substation.

Frank P. Pozniak

Hearing Officer

APPROVED by a majority of the Energy Facilities Siting Council by the members and designees present and voting. Voting for approval of the tentative decision as amended: Sharon M. Pollard (Secretary of Energy Resources); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Paul Romary (for Paula Gold, Secretary of Consumer Affairs); and Fred Hoskins (for Joseph Alviani, Secretary of Economic Affairs). Voting against approval of the tentative decision as amended: Stephen Umans (Public Electricity Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Dennis LaCroix (Public Gas Member).

Sharon M. Pollard
Chairperson

Dated this 30th day of June, 1988

APPENDIX A

NAME	ADDRESS
Forest A. and Barbara Eaton	46 Beach Plum Circle Harwich, MA 02645
Carl and Alice Fritz	27 Katie Ford Road West Chatham, MA 02669
Philip and Marion Gately	50 Beach Plum Circle Harwich, MA 02645
Ruth Gomes	Main Street, P.O. Box 88 Harwich, MA 02645
Larry Keyes	26 Obed Brooks Road, RR3 Harwich, MA 02645
Mrs. Julia Lincoln	614 Queen Anne Road Harwich, MA 02645
Jeraldine Lopes	518 Queen Anne Road Harwich, MA 02645
Irving MacFarland	16 Oak Leaf Circle Harwich, MA 02645
Thomas and Frances McLaughlin	54 Barrows Street Dedham, MA 02026
Carlota F. Pena	368 Main Street N. Harwich, MA 02645
William and Dorothy Sheehy	38 Beach Plum Circle Harwich, MA 02645
Charles Williams	Mallard Lane, P.O. Box 1560 Orleans, MA 02653
Jack and Marian Long	17 Lakewood Lane Harwich, MA 02645
Ester and Eben Hinkley	Queen Anne Rd. East Harwich, MA 02645
Ada and Paul Litchfield	511 Queen Anne Road Harwich, MA 02645
Daniel J. Roderick, Executor for the Estate of Anna Roderick	Box 910 Harwich, MA 02645

APPENDIX A (Cont.)

Ronald and Beverly Farris	off Samoset Road Harwich, MA 02645
Reginald B. and Ruth G. Keyes	Queen Anne Road Harwich, MA 02645
Daniel Sylver	off Samoset Road Harwich, MA 02645
Jacqueline Rixon	22 Quail Nest Run Harwich, MA 02645
Roland Mayo	14 Longview Drive Orleans, MA 02653
Lois A. Brooks	Box 292 Harwich, MA 02645
Mr. and Mrs. Robert Dalldors	6 Quailnest Run Harwich, MA 02645
Margaret Duflo	28 Samoset Road Harwich, MA 02645
Mrs. Robert Drummond	21 Samoset Road Harwich, MA 02645
Mrs. A. Earl Godshall	9 Samoset Road Harwich MA 02645
Mr. and Mrs. William Scarry	29 Samoset Road Harwich, MA 02645
Dr. and Mrs. Sherman Santoian	11 Samoset Road Harwich, MA 02645
Mr. And Mrs. Walter Hart	2 Samoset Road Harwich, MA 02645
Mr. Arthur Beatty	4 Samoset Road Harwich, MA 02645
Mr. and Mrs. James Smith	11 Samoset Road Harwich, MA 02645
A. Mae Torres	726 Queen Anne Road Harwich, MA 02645
Willard H. Nickerson, Jr.	Btwn Rte. 137 and Hawksnest Road Harwich MA 02645
Ellen L. Farris	Btwn Rte. 137 and Hawksnest Road Harwich MA 02645

APPENDIX A (Cont.)

Mabel L. Reddish	Btwn Rte. 137 and Hawksnest Road Harwich MA 02645
Alice Guiliana Dexter	Btwn Rte. 137 and Hawksnest Road Harwich MA 02645
Celia Mabel Mallowes	Btwn Rte. 137 and Hawksnest Road Harwich MA 02645

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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 (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Altresco-Pittsfield, Inc. for Approval to Construct a Bulk Generating Facility	EFSC 88-100

FINAL DECISION

Robert D. Shapiro
Hearing Officer
August 4, 1988

On the Decision:

Pamela Maclean Chan
Brian G. Hoefler

TABLE OF CONTENTS

FIGURES AND TABLES:

The Energy Facilities Siting Council hereby APPROVES, subject to CONDITIONS, the petition of Altresco-Pittsfield, Inc. to construct a 156 megawatt bulk generating facility and ancillary facilities in Pittsfield, Massachusetts.

I. INTRODUCTION

A. Summary of the Proposed Project and Facilities

Altresco-Pittsfield, Inc. ("Altresco" or "Company"), a wholly-owned subsidiary of Altresco, Inc., has proposed to construct a 156 megawatt[1] ("MW") combustion turbine, combined-cycle cogeneration facility at General Electric's manufacturing and research complex in Pittsfield, Massachusetts ("GE-Pittsfield") (Exh. HO-1, p. 1-1). The primary fuel for the proposed facility would be natural gas, although the facility would be capable of burning distillate oil subject to air emission regulations (id., pp. 2-7 to 2-9, 6-21). The facility will utilize selective catalytic reduction ("SCR") in combination with steam injection for the control of nitrogen oxides ("NO_x") emissions; this combination of technologies is considered to represent the "Lowest Achievable Emission Rate" ("LAER") under Federal Environmental Protection Agency ("EPA") regulations (id., pp. 1-2, 2-3, 5-6, 6-1 to 6-3, 6-21).

Altresco's petition includes a request to construct the generating facility, along with the following ancillary facilities: (1) a 600-foot, 115 kilovolt ("kV") transmission line to interconnect the power plant with an existing 115 kV substation on the GE-Pittsfield property; (2) a "day tank" for storage of distillate fuel oil, and (3) an oil pipeline to connect the facility to existing oil storage tanks

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1/ While the Altresco petition is for a 156 MW bulk generating facility, the actual electrical generation capability of the facility will vary depending on ambient temperature conditions and steam flow to process rates (Exhs. HO-21, HO-GE-1). The nominal generating capacity of the proposed facility would be approximately 160 MW with a maximum capability of approximately 166 MW based on GE steam flow requirements (id.).

within the GE-Pittsfield complex (id., pp. 2-9, 2-10, 2-19; Exhs. HO-E-14, HO-O-3). Altresco estimated the total cost of the proposed facilities to be approximately $151 million (Exh. HO-1, p. 2-12). While Altresco's initial petition included a 2500-foot gas pipeline spur to connect the facility to a nearby Berkshire Gas Company ("Berkshire") metering station, Altresco later amended its petition to eliminate this spur (Exh. HO-1, p. 2-8; Tr. 1, pp. 11-12).[2]

Altresco has received certification from the Federal Energy Regulatory Commission ("FERC") that the project constitutes a "Qualifying Facility" ("QF") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"), which requires electric utility companies to purchase power from QFs for a price at or below the utility's avoided cost of production (Exh. HO-1, Appendix E).[3] The FERC certification of Altresco as a QF is based upon a finding that Altresco would sell enough of the facility's steam by-product so as to qualify as a cogeneration facility (id.).

Altresco has signed a 20-year Power Purchase Agreement ("PPA") with Massachusetts Electric Company ("MECo") for 100 MW of power beginning as early as December 1, 1989, but subject to the condition that the facility be on line no later than June 1, 1990 (Exh. HO-1, Appendix C). The PPA allows MECo, at its sole option, to purchase any portion of the remainder of the output that is not under contract to another utility at a future time (id.). Altresco also has signed a second PPA to supply 25 MW to MECo beginning in 1991 in the event that it fails to meet the conditions required by MECo for the supply of the 100 MW set forth in the first PPA (id.). Further, Altresco has submitted a bid to supply 30 MW to Eastern Utilities Associates ("EUA")

2/ Altresco has entered into a preliminary agreement with Berkshire under which the facility will receive natural gas, its primary fuel, from a new pipeline that will connect with an existing interstate gas pipeline (id.). The new pipeline will be paid for by Altresco, and designed, constructed, maintained, and owned by Berkshire (Exh. A-10a).

3/ FERC granted QF status to the Altresco project in February 1988 (Exh. HO-1, Appendix E).

in response to EUA's January 1988 power purchase solicitation (Exhs. HO-1, p. 4-11, HO-E-5). In addition, Altresco and EUA are discussing the sale of 20 to 30 MW of power separate from the bidding process (that is, as a substitute for the power sought in the bidding process) (Tr. 3, pp. 95-96; Exh. HO-34). Altresco has stated that any unsold power would be available to utility companies in New England (Exh. HO-1, p. 1-3).

The Altresco project is the second bulk power generating facility presented by a non-utility-company developer to the Energy Facilities Siting Council ("Siting Council") for approval (see Northeast Energy Associates, 16 DOMSC 335 (1987) (hereinafter cited as "NEA")). The Company was incorporated in Massachusetts in May 1987 (Exh. HO-B-11). Its parent company, Altresco, Inc., is a privately-held Colorado corporation founded in April 1986 for the purpose of investing in energy projects (Exh. HO-1, p. 1-1). This is the first energy project for either organization (Exhs. HO-B-3, HO-B-10).

B. Procedural History

On February 10, 1988, Altresco filed its "Petition Before the [Siting Council] for Approval to Construct a Bulk Generating Facility" for approval of the cogeneration facility described herein (Exh. HO-1).[4] On March 22, 1988, the Siting Council conducted a public hearing in the City of Pittsfield ("Pittsfield"). In accordance with the directions of the Hearing Officer, Altresco provided notice of the public hearing and adjudication.

On March 28, 1988, John Beucler ("Beucler") filed a petition to participate as an interested party. On March 30, 1988, the Allendale Elementary School filed a similar petition. On April 13, 1988, the Hearing Officer conducted a pre-hearing conference to rule on the petitions to participate, and to establish a procedural schedule for the remainder of the proceeding. At the conference, the Hearing Officer granted the petitions of Beucler and the Allendale Elementary School.

4/ As stated above, the Company later amended its petition by eliminating the proposed gas spur (Tr. 1, p. 11).

The Siting Council conducted five evidentiary hearings between May 10, 1988, and May 23, 1988. Altresco presented eleven witnesses: David Adams, an environmental engineer for General Electric, who testified regarding environmental impacts of the proposed project; Theodore Barten, manager of the environmental engineering permitting division at HMM Associates, who testified regarding alternate technologies and water impacts; Michael Nielsen, a senior project manager with Woodward-Clyde Consultants, who testified regarding air impacts; Robert Berens, an analyst with HMM Associates, who testified regarding noise impacts; Henry Lee, Executive Director of Harvard University's Energy and Environmental Policy Center, who testified regarding need for the proposed facility; Mary Smith, coordinator of energy projects for New England Power Service Company, who testified regarding the Company's PPA; Herbert Hand, an engineer associated with Miller-Kerr Inc., who testified regarding the PPA and project construction contracts; William Williams, chairman and chief executive officer of Altresco, Inc.; Barry Curtiss-Lusher, a member of the Altresco, Inc., Board of Directors, who testified regarding fuel supply and transportation; William Palmer, Executive Vice-President of Market Development of Altresco, Inc., who testified regarding facility design and steam requirements; and Merrill Ring, a partner in Private Capital Partners, Inc., who testified regarding project financing.

The Hearing Officer entered 146 exhibits in the record, largely composed of Company responses to information and record requests. Twenty-five of Altresco's exhibits were also entered into the record.

Pursuant to a briefing schedule established by the Hearing Officer, Altresco filed its brief ("Initial Brief") on June 10, 1988. On the same date, Beucler filed comments. On June 13, 1988, Allendale Elementary School filed comments. On July 8, 1988, Altresco filed a supplemental brief ("Supplemental Brief").

C. Jurisdiction

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

As a combined-cycle cogeneration facility with a capacity of approximately 156 MW, Altresco's proposed generating unit falls squarely within the first definition of "facility" set forth in G.L. c. 164, sec. 69G. That section states, in part, that a facility is:

> (1) any bulk electric generating unit, including associated buildings and structures, designed for, or capable of operating at a gross capacity of one hundred megawatts or more.

At the same time, Altresco's proposal to construct a transmission line, oil storage facilities, and an oil pipeline, falls within the third definition of "facility" set forth in G.L. c. 164, sec 69G, which states that:

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

In accordance with G.L. c. 164, sec. 69H, before approving an application to construct facilities, the Siting Council requires applicants to justify facility proposals in three phases. First, the Siting Council requires the applicant to show that additional energy resources are needed (see Section II.A, infra). Next, the Siting Council requires the applicant to establish that its project is superior to alternate approaches in terms of cost, environmental impact and ability to address the previously identified need (see Section II.B, infra). Finally, the Siting Council requires the applicant to show that the proposed site for the facility is superior to alternate sites in terms of cost, environmental impacts, and reliability of supply (see Section III, infra).

II. ANALYSIS OF THE PROPOSED PROJECT

A. Need Analysis

1. Standard of Review

In accordance with G.L. c. 164, sec. 69H, the Siting Council is charged with the responsibility for implementing energy policies to provide a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

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

In evaluating the need for new energy facilities to meet reliability objectives, the Siting Council has evaluated 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 Council 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. NEA, supra, at 344-360; Cambridge Electric Light Company, 15 DOMSC 187, 211-212 (1986); Massachusetts Electric Company, 13 DOMSC 119, 137-138 (1985); New England Electric System, 2 DOMSC 1, 9 (1977); Eastern Utilities Associates, 1 DOMSC 312, 313-314 (1977). With regard to contingencies, the Siting Council has found that new capacity is needed in order to ensure that service to firm customers can be maintained

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

in the event that a reasonably likely contingency occurs. Middleborough Gas and Electric Department, EFSC 87-18, pp. 17-20 (1988); Boston Edison Company, 13 DOMSC 63, 70-73 (1985); Taunton Municipal Lighting Plant, 8 DOMSC 148, 154-155 (1982); Commonwealth Electric Company, 6 DOMSC 33, 42-44 (1981); Eastern Utilities Associates, supra, at 316-318; Massachusetts Municipal Wholesale Electric Company, 1 DOMSC 101, 102-104 (1977).

The Siting Council also has determined in some instances that utilities need to add energy resources primarily for economic efficiency purposes. The Siting Council has found that a utility company's proposed energy facility was needed principally for providing economic energy supplies relative to a system without the proposed facility. Massachusetts Electric Company, supra, at 178-179, 183, 187, 246-247; Boston Gas Company, 11 DOMSC 159, 166-168 (1984).

While G.L. c. 164, sec. 69H, requires the Siting Council to ensure an adequate supply of energy for Massachusetts, the Siting Council has interpreted this mandate broadly to encompass not only evaluations of specific need within Massachusetts for new energy resources (Boston Edison Company, supra; Hingham Municipal Lighting Plant, 14 DOMSC 7 (1985)), but also the consideration of whether proposals to construct energy facilities within the Commonwealth are needed to meet New England's energy needs. NEA, supra, at 344-360; Massachusetts Electric Company, 15 DOMSC 241, 273, 281 (1986); Massachusetts Electric Company, 13 DOMSC 119, 129-131, 133, 138, 141 (1985); Massachusetts Electric Company, 2 DOMSC 1, 4-6 (1977). In so doing, the Siting Council has fulfilled the requirements of G.L. c. 164, sec. 69J, which recognizes that Massachusetts' generation and transmission system is interconnected with the region's and that reliability and economic benefits flow to Massachusetts from Massachusetts' utilities' participation in the New England Power Pool ("NEPOOL").

In cases where a non-utility-company developer seeks to construct a jurisdictional QF facility principally for a single specific utility purchaser, the Siting Council requires the applicant to demonstrate that the utility needs the facility to address reliability concerns or economic efficiency goals. Where a non-utility developer has proposed a QF 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, need may be established on a regional basis on either reliability or economic efficiency grounds. NEA, supra, at 344-360. However, the non-utility developer that proposes a QF facility to serve a regional need must also demonstrate to the Siting Council that the proposed facility benefits Massachusetts -- that is, it offers reliability or economic efficiency benefits to the Commonwealth in sufficient magnitude so that the construction of an energy facility in the state is consistent with the energy needs and resource use and development policies of the Commonwealth. Id.

2. Status of Altresco's Power Sales Agreements

Altresco has demonstrated to the Siting Council that it has (1) a signed and approved PPA with MECo for 100 MW, and (2) a signed and approved PPA with MECo for 25 MW that would replace the 100 MW PPA in the event the 100 MW agreement is terminated (Exh. HO-1, p. 4-11 and Appendix C). It has also indicated that it has offered to sell to EUA, and EUA is interested in purchasing, an additional 20 to 30 MW, either as a part of EUA's January 1988 power purchase solicitation or outside of that process (Exhs. HO-E-5, HO-34; Tr. 3, pp. 95-96). If Altresco sells 100 MW to MECo but does not enter into any agreements with EUA, there would be up to 56 MW that Altresco would have available to market to other utilities in the region (Exh. HO-1, p. 1-3). Because Altresco proposes to construct a facility for a number of power purchasers, including purchasers that are yet unknown, the Siting Council evaluates whether New England needs the proposed 156 MW of additional energy resources for reliability or economic efficiency purposes by 1990,[6]

6/ The Siting Council evaluates need beginning in 1990, the first full year in which the 100 MW PPA with MECo will be effective.

and whether Massachusetts is likely to receive reliability or economic efficiency benefits from the proposed additional energy resource beginning in 1990.

3. New England's Need for Additional Energy Resources

Altresco argues that New England needs additional energy resources for reliability (Exhs. HO-1, pp. 3-1 to 3-5; HO-N-1a). Altresco asserts that the region needs additional energy resources because projected capacity in New England is inadequate to satisfy the region's projected load and reserve requirements (id.).

In support of its argument that New England needs additional power resources for reliability purposes, Altresco provided an analysis of electricity demand and supply in New England (Exh. HO-1, Appendix H). This analysis was previously presented to the Siting Council in NEA, supra, at 344-360, in connection with Northeast Energy Associates' proposal to construct a 300 MW bulk generating station in Bellingham, Massachusetts ("NEA analysis"). Altresco asserts that, with certain updates, the NEA analysis continues to reflect the New England demand and supply situation (Exh. HO-N-1a).

The NEA analysis, prepared by Mr. Henry Lee, evaluated the base assumptions and results of the projections included in the following documents: (1) the NEPOOL "Forecast Report of Capacity, Energy, Loads and Transmission, 1986-2001" ("1986 CELT Report"); (2) the "Contingency Case" developed by the New England Governors' Conference, Inc. ("NEGC") in conjunction with NEPOOL member utilities as part of a December 1986 report; and (3) a forecast presented by an independent power producer, Ocean State Power ("OSP"), as part of its January, 1987 application to the Rhode Island Energy Facilities Siting Board ("RI Siting Board") (Exhs. HO-1, Appendix H, HO-N-3a, HO-N-3b, HO-N-3c).

The NEPOOL summer peak growth rate was projected in these three reports as follows: 2.2 percent per year through 2001 in the 1986 CELT Report; 3.0 percent per year until 1989 and 1.6 percent per year thereafter in the OSP forecast; and 4.0 percent per year from 1987-1991, followed by a 3.2 percent per year thereafter in the NEGC report (id.).

In addition, as part of the NEA analysis, Mr. Lee developed a fourth, mid-range, growth scenario through the year 2000 (id.). This scenario was based on assumptions of a 4.0 percent annual growth rate for the period 1987-1991, followed by the NEPOOL historical growth rate of 2.7 percent annually (id.).

Based on these four scenarios, Northeast Energy Associates asserted that, despite the considerable conservation and load management included in the projections, New England needed to add a significant amount of capacity starting in the 1988 to 1990 period to meet forecasted load and reserve requirements (id.). In the NEA case, the Siting Council found that the applicants (1) presented a reasonable range of plausible forecasts, and (2) adequately analyzed the sensitivity of forecast results to changes in critical assumptions (p. 354). Based on these findings, the Siting Council held that Northeast Energy Associates had (1) provided projections of the demand for electric power and the capacities of existing and proposed facilities that are based on substantially accurate historical information and reasonable statistical projection methods, and (2) established that New England needs at least 300 MW of additional power resources for reliability purposes by 1990. Id.

Altresco presented an update of the NEA analysis, also prepared by Mr. Lee, which included revised demand projections based on the same four scenarios included in the NEA analysis, recalculated to reflect the winter peak of 1987-1988 (Exhs. HO-N-1a, HO-N-1b, A-2). The updated analysis concluded that, based on the 1987-1988 winter peak demand, the higher growth forecast scenarios of the NEA analysis were sound (id.). Altresco asserted that, "barring a significant recession in the near future ... the range of growth projections presented in these cases is reasonable" (Exh. HO-N-1a).

Altresco sponsored the testimony of Mr. Lee regarding the continued validity of the basic assumptions and resulting conclusions of the NEA analysis. Specifically, Mr. Lee testified that, based on world events, their impact on overall economic and energy factors, and continued local economic growth, the assumptions in the NEA analysis were still valid (Tr. 2, pp. 74-76). Thus, Altresco asserts that the NEA analysis, with updates based on the actual 1988 winter peak demand data, supports the regional need for the proposed project (Initial Brief, pp. 8-9).

The Siting Council found in the NEA case that an applicant may rely on "various forecasts prepared recently by industry and government organizations in the region" (p. 353). In lieu of its own forecast, Altresco has presented revised versions of the four forecasts presented in the NEA analysis. However, in light of the age of these forecasts, the Siting Council must address the issue of whether these forecasts, as revised by Altresco, remain plausible.

NEPOOL's 1988 CELT Report, dated April 1, 1988, is clearly an appropriate update to the 1986 and 1987 CELT Reports reviewed in the NEA analysis (Exh. HO-3). However, the Siting Council notes that (1) the NEGC forecast was prepared in December 1986; (2) the OSP forecast was prepared for submission to the RI Siting Board in January 1987; and (3) Mr. Lee's own mid-range growth scenario was prepared in June, 1987 (Exhs. HO-N-3b, HO-N-3c, HO-1, Appendix H).

The Siting Council acknowledges the problems in forecasting demand growth in a dynamic energy marketplace such as New England, and notes that this is all the more reason a project proponent must utilize the most current information for forecasting purposes. In the instant case, the proponent based its projections on data which were, in some cases, more than one year old. Even so, given that (1) Altresco recalculated the older demand forecasts based on the past winter's electricity demand, and (2) that the variety of forecast sources provides a significant bandwidth (see Tables 1 and 2 herein), the Siting Council accepts the scenarios presented as a reasonable range of plausible demand forecasts which provide an adequate basis for testing changes in critical demand assumptions.

In regard to supply projections, Altresco failed to update the OSP and NEGC forecasts to incorporate the growth in third-party power supply in the region. For example, except for the 1988 CELT report, none of the supply projections presented by Altresco included the combined 450 MW from OSP Phase 1 and OSP Phase 2 which NEPOOL expects to be on-line prior to the summer of 1991, or the planned 300 MW from Northeast Energy Associates which was proposed to be on line prior to the summer of 1990 (Exh. HO-3; see NEA, supra, at 384). Although it is difficult to predict with certainty if and when generating facilities will begin generating power, particularly when the permitting process for such facilities have not been completed, the growing number of new supply sources in the region warrants consideration of appropriate, current supply projections.

At the same time, Alresco's supply projections failed to address the capability of existing supply. Despite Mr. Lee's skepticism regarding recent performance of large baseload plants (Exh. HO-N-1a), none of the Company's supply projections adequately consider possible reductions in existing supply.

Because Altresco has failed to update the NEA analysis of regional supply to include new generating facilities, and has failed to adequately consider the reliability of existing supplies, the Siting Council makes no findings regarding the plausibility of Altresco's supply projections. However, for purposes of this review, The Siting Council addresses supply scenarios which include NEA, OSP Phase 1, and OSP Phase 2.

Altresco's projections of regional demand and supply under each of its four forecasts are presented in Tables 1 and 2. These forecasts indicate the need for additional power resources in 1990 under most assumptions. By 1995, all scenarios indicate a need for substantial supply additions. The Siting Council notes that the addition of power from the Northeast Energy Associates' project and from OSP Phase 1 and OSP Phase 2 projects is insufficient to meet projected demand under most of Altresco's demand/supply scenarios.

Based on the foregoing, the Siting Council finds that the record in this proceeding contains substantially accurate historical demand and supply information and forecasts based on reasonable statistical projection methods. Accordingly, based on the record in this proceeding, the Siting Council finds that Altresco has established that New England needs at least 156 MW of additional energy resources for reliability purposes by 1990.

4. Benefits to Massachusetts

Having established that New England needs at least 156 MW of additional energy resources to meet reliability objectives by 1990, the Siting Council determines whether the proposed project is likely to provide reliability or economic efficiency benefits to Massachusetts by that date as well.

a. Power Sales

In NEA the Siting Council found that, consistent with current resource use and development policies of the Commonwealth, ratepayers in Massachusetts benefit economically from the addition of cost effective QF resources to their utilities' supply mix (p. 358). In that case, the Siting Council also found (1) that a signed and approved power sales agreement 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 power sales agreement which includes a capacity payment constitutes *prima facie* evidence of the need for additional energy resources for reliability purposes. *Id.*

Here, Altresco argues that its proposed project is consistent with policies of the Commonwealth and that its power sales agreement with MECo demonstrates that Massachusetts will benefit from additional energy resources for economic efficiency and reliability purposes (Initial Brief, pp. 9-11).

Altresco submitted a copy of its signed agreement to sell 100 MW to MECo beginning December 1, 1989, an agreement that provides for capacity payments to the Company (Exh. HO-1, Appendix C). The Company's witness, Mary Smith of MECo, testified that capacity from Altresco is part of MECo's future supply plans (Tr. 3, pp. 12-13). The Company noted that this power sales agreement was approved by the Massachusetts Department of Public Utilities ("DPU") on June 24, 1988 (Exh. A-17).

Based on the foregoing, the Siting Council finds that Altresco has established that the ratepayers of MECo are likely to receive economic efficiency and reliability benefits from the proposed additional power resources. Accordingly, the Siting Council finds that Altresco has established that Massachusetts is likely to receive economic efficiency and reliability benefits beginning in 1990 from Altresco's PPA with MECo.

b. Steam Sales

Altresco also argues that its proposed project would provide substantial economic and environmental benefits to the Pittsfield area due to GE-Pittsfield's need for a new cost-effective, reliable, and environmentally-acceptable steam supply (Initial Brief, p. 11).

Altresco maintains that its steam sales agreement provides economic benefits to GE-Pittsfield by selling steam to the complex at a cost that is less than one-fourth GE-Pittsfield's cost to construct and operate its own facility (Initial Brief, p. 11). Under its contract with Altresco, GE-Pittsfield is expected to spend approximately $1 million on steam purchases (based on GE-Pittsfield's estimated minimum steam requirements of 840,000,000 lbs per year at a price of approximately $1.19 per 1000 lbs (Exhs. HO-1, p. 2-5, HO-7, HO-S-3). If GE-Pittsfield exercises its option to purchase a lower quantity of steam, the unit price would be less than $1.19 per 1000 lbs (Exh. HO-S-3). For example, if GE-Pittsfield required 800,000,000 lbs of steam in one year, the cost would be about $864,800 or $1.08 per 1000 lbs (Exhs. HO-7, HO-S-3)). Altresco asserted that GE-Pittsfield's unit cost of steam during 1987 was $8.40 per 1000 lbs, of which about half could be attributed to fuel charges, and the remainder to operating and maintenance expenses and capital costs of the physical plant (Exh. HO-7). Based on a recent boiler replacement at GE's plant in Lynn, Massachusetts, Altresco estimated GE-Pittsfield's capital cost of constructing its own steam generating plant to be about $1.25 per 1000 lbs (id.). However, Altresco did not provide sufficient information to determine the fuel costs and operation and maintenance expenses associated with a steam generating plant constructed by GE-Pittsfield.

Further, Altresco's analysis assumed that GE-Pittsfield would not take the very course taken by Altresco -- cogeneration of steam and electricity -- to achieve greater energy efficiency and thereby reduce unit costs. Therefore, the Siting Council rejects Altresco's assertion that it could sell steam to GE-Pittsfield at less than one-fourth of GE-Pittsfield's cost to construct and operate its own facility.

The Company, nevertheless, has established that replacement of GE-Pittsfield's existing steam boilers through a steam sales agreement with Altresco would result in a unit cost for steam that is substantially less than the current cost of generating GE-Pittsfield's steam. Indeed, at a cost of $8.40 per 1000 lbs, GE-Pittsfield's cost to generate 840,000,000 lbs of steam per year is about $7 million -- $6 million more than the price at which Altresco would sell steam. Thus, when compared to GE-Pittsfield's existing steam supply, the proposed project would provide significant economic benefits to GE-Pittsfield, a major employer in the Pittsfield area with about 7,000 workers (Exhs. HO-1, pp. 6-18, HO-GE-4).

In regard to environmental impacts, Altresco estimated that replacing GE-Pittsfield's present oil-fired boilers with boilers fired primarily by gas, and using steam injection and SCR technologies, would reduce sulfur dioxide ("SO_2") emissions from about 850 tons per year ("TPY") to about 90 TPY (Exhs. HO-1, p. 6-4, HO-EN-9). The Company also estimated that this replacement would increase NO_x emissions from about 170 TPY to about 213 TPY (id.). The Siting Council notes, however, that on balance, the replacement of the oil-fired boilers would improve air quality. Moreover, GE-Pittsfield is subject to a Massachusetts Department of Environmental Quality Engineering ("DEQE") Administrative Consent Order issued pursuant to 310 CMR 7.01, "General Regulations to Prevent Air Pollution," requiring GE-Pittsfield to replace its oil-fired boilers by January 1, 1991 (Exh. HO-EN-1).

In its NEA decision, the Siting Council established that a non-utility-company developer proposing the addition of energy resources in the Commonwealth must demonstrate that it offers reliability or economic efficiency benefits to the Commonwealth in sufficient magnitude so that construction of an energy facility in the state is consistent with the energy needs, and resource use and development policies of the

Commonwealth. NEA, supra, at 349. Here, pursuant to G.L. c. 164, sec. 69J, the Siting Council finds that a non-utility-company developer also may demonstrate benefits to the Commonwealth based on economic grounds outside of a power sales agreement or on environmental grounds if such benefits are consistent with the policies of the Commonwealth.

Based on the foregoing, the Siting Council finds that Massachusetts is likely to receive economic and environmental benefits beginning in 1990 from Altresco's steam sales agreement with GE-Pittsfield.

c. Conclusions on Benefits to Massachusetts

The Siting Council has found that (1) Massachusetts is likely to receive reliability and economic efficiency benefits beginning in 1990 from Altresco's PPA with MECo, and (2) Massachusetts is likely to receive other economic, as well as environmental benefits, from Altresco's steam sales agreement with GE-Pittsfield by that date as well.

Accordingly, the Siting Council finds that Massachusetts is likely to receive reliability, economic efficiency, and environmental benefits beginning in 1990 from the additional energy resources proposed in this project.

6. Conclusion on Need

The Siting Council has found that (1) Altresco has established that New England needs at least 156 MW of additional energy resources for reliability purposes by 1990, and (2) Massachusetts is likely to receive reliability, economic efficiency, and environmental benefits from the additional energy resources within the same time frame. Accordingly, the Siting Council finds that the proposed 156 MW of additional energy resources are needed by 1990.

B. Comparison of the Proposed Project and Alternative Approaches

1. Standard of Review

G.L. c. 164, sec. 69H, requires the Siting Council 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 lowest possible cost. In addition, G.L. c. 164, sec. 69I, requires a project proponent to present "alternatives to planned action" which may include (a) other methods of generating, manufacturing or storing, (b) other sources of electrical power or gas, and (c) no additional electrical power or gas.[7]

In implementing its statutory mandate, the Siting Council has required a petitioner to show that, on balance, its proposed project is superior to alternate approaches in the ability to address the previously identified need and in terms of cost and environmental impact. Additionally, where a non-utility developer proposes to construct a QF facility in Massachusetts, the Siting Council determines whether the project offers power at a cost below the purchasing utility's avoided cost and is likely to be viable as a source of energy over time. NEA, supra, at 360-380; Cambridge Electric Light Company, supra, at 212-218; Massachusetts Electric Company, 13 DOMSC 119, 141-183 (1985); Boston Edison Company, supra, at 67-68, 73-74.

2. Need

To address the identified need for at least 156 MW of additional energy resources by 1990, Altresco proposes to construct a 156 MW, dual-fuel combined-cycle cogeneration power plant in Pittsfield (Exh. HO-1, p. 3-1). Altresco noted that additional benefits of the proposed

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7/ G.L. c. 164, sec. 69I, also requires a petitioner to provide a description of "other site locations." The Siting Council reviews the Company's proposed site, as well as other site locations, in Section III, infra.

cogeneration project include substantial steam sales[8] to GE-Pittsfield, which would provide significant economic and environmental advantages (id., p. 3-5). Altresco stated that its proposed project should be on line by 1990 (id., p. 2-11).

Altresco discussed several alternate approaches to addressing the identified need including non-conventional and conventional technologies (Exh. HO-1, pp. 4-2 to 4-3). The Company stated, however, that non-conventional technologies such as biomass-fired and refuse-fired plants typically are too small to address the identified need (id.). For example, the size of biomass-fired plants normally ranges from 10 to 25 MW due to the difficulty in obtaining sufficient fuel supplies, and the largest biomass-fired plant in New England is only 50 MW (id.). The Company argued that a refuse-fired plant also would be too small to adequately address need. First, the largest refuse-fired plant in Massachusetts burns 1500 TPD but has a capacity of only 40 MW (id.). In addition, the Company argues that a 400 TPD refuse-fired plant already operates in Pittsfield and uses most of the refuse available in Berkshire County (id.). Altresco did not indicate whether any of the alternatives discussed above could cogenerate steam and thus provide the identified economic and environmental benefits to Massachusetts of steam sales to GE-Pittsfield.

Conventional oil-fired or coal-fired, steam cycle power plants could be designed to generate 156 MW or more and provide steam to the GE-Pittsfield complex (id.). However, the Company asserted that licensing and constructing such plants would require considerably longer lead times, effectively eliminating them from consideration because they could not meet the 1990 time frame (id.). Altresco did not provide any basis for determining the length of time necessary to place such plants in service.

8/ Altresco's application to FERC for certification as a QF estimated that steam sales would amount to about 18 percent of total energy output from the proposed project (Exh. HO-1, Appendix F).

The Siting Council finds that Altresco has demonstrated that non-conventional technologies such as biomass-fired and refuse-fired plants fail to address the identified need. Therefore, in reviewing the cost and environmental impacts of the proposed project, the Siting Council compares the proposal to the alternatives of conventional oil-fired and coal-fired, steam cycle power plants. Further, the Siting Council finds that the proposed project is superior to the oil and coal alternatives with respect to addressing the identified need.

3. Cost

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

Altresco maintains that the decision by the Siting Council in NEA that Northeast Energy Associates' "gas-fired combined cycle cogeneration technology is superior to alternatives in terms of cost" establishes a presumption that the Altresco project, which is also a gas-fired combined-cycle cogenerator, is superior to alternatives in terms of cost (Initial Brief, p. 13; Exh. HO-1, pp. 4-2, 4-3). In this case, Altresco presented a comparison of the costs of its project relative to the costs of the Northeast Energy Associates' project (Initial Brief, pp. 13-14). At the same time, the Company also presented a comparison of its project's costs and costs of (1) a conventional coal project, and (2) a conventional oil project (Exh. HO-6).

In comparing the costs of the proposed project and Northeast Energy Associates' project, Altresco conceded that the capital costs of the Altresco project, at $900 per kw, are relatively high due to the use of three medium-sized turbines for steam supply reliabilty (id.). In comparison, the capital costs of the NEA project were calculated at $666 per kw (id.; NEA, supra, at 370). Still, Altresco maintains that the total levelized busbar cost per kilowatt hour ("kwh") for the proposed project would, in fact, be less than that of the NEA project (Initial Brief, p. 14).

In regard to the coal and oil alternatives, Altresco asserts that both would have higher capital costs, higher operation and maintenance costs, and lower availability than the proposed project (Exh. HO-6). In addition, the oil alternative would have higher fuel costs per Btu (id.). Altresco stated that, while the coal alternative might have lower fuel costs than the proposed project, the costs of both the oil and coal alternatives, on balance, would be higher than the costs of the proposed project (id.).

In NEA, the Siting Council established standards for determining whether a proposed project is superior to alternate approaches in terms of cost (pp. 371-373). In that case, the Siting Council found that a comparative cost analysis for a generating project should (1) adequately evaluate a reasonable range of generating options, (2) analyze specific costs of the proposed technology and compare them to the costs of other technologies, and (3) place the project within the Commonwealth's energy policies. In that same case, the Siting Council criticized the Company for failing to place an economic value on the advantages of cogeneration projects relative to other projects.

Although the Siting Council previously has found that a dual-fuel combined-cycle cogeneration project is superior to alternate approaches in terms of cost, such a finding cannot foreclose future reviews of that technology relative to costs of alternate approaches. While the dual-fuel cogeneration project was shown to be least cost in the NEA case, that cost determination was based on the specific attributes of that project. The technological advances in the energy resource arena, and the cost implications that arise from those advances, in addition to variations in other significant project components, require a thorough review in each case. Therefore, the Siting Council finds that a comparative cost analysis between the Altresco project and the Northeast Energy Associates project is not determinative in this case. The Siting Council proceeds to review the Company's analysis of project costs relative to the costs of oil and coal alternatives.

The Siting Council finds that Altresco has submitted a cost analysis which meets the standards set forth in the NEA decision. At the same time, the Siting Council notes that the Company has appropriately limited its analysis to competing technologies that are capable of meeting the requisite steam demand. Accordingly, the Siting Council finds that the Company has established that its proposed project is superior to a reasonable range of alternate approaches in terms of cost.

Altresco also asserts that its project offers power to MECo at a price significantly below that utility's avoided cost (Initial Brief, p. 16). Altresco presented to the Siting Council MECo's filing before the DPU and the DPU's decision in that case (Exhs. HO-20; A-17). Altresco stated that MECo's analysis of three scenarios in the DPU filing shows that total savings to the ratepayers would range from $73 million to $130 million over the life of the 100 MW contract (Initial Brief, p. 16). In its decision on the MECo contracts, the DPU found that "the contracts provide for the sale of electricity under terms and conditions which are likely to provide benefits to [MECo] and its ratepayers over the lives of the agreements" (Exh. A-17). Altresco's witness, William Williams, stated that any future power sales contracts would mirror the MECo contract (Tr. 3, p. 103).

Based on the foregoing, the Siting Council finds that Altresco has established that its proposed project offers power at a cost below the purchasing utility's avoided cost.

Pursuant to the Siting Council's finding that Altresco has demonstrated that (1) its proposed project is superior to a reasonable range of alternate approaches on the basis of cost, and (2) its proposed project offers power at a cost below the purchasing utility's avoided costs, the Siting Council finds that Altresco has demonstrated that its proposed project minimizes cost.

4. Environmental Impacts

Altresco maintains that a gas-fired combined-cycle cogenerator with SCR is superior to alternatives in terms of environmental impacts

(Initial Brief, p. 17). In support of its position, Altresco presented an analysis comparing the environmental impacts of the proposed facility to the environmental impacts of coal and oil alternatives of the same generating capacity (Exh. HO-1, pp. 4-5 to 4-10). Altresco maintains that its analysis shows its proposed project to be superior to the alternatives in terms of environmental impacts from fuel transportation arrangements, land requirements, air emissions, water supply and waste-water discharge, and solid and liquid waste by-products (Initial Brief, p. 17). Additionally, Altresco stated that "the superiority of the project from an environmental standpoint is further substantiated by the receipt of the MEPA [Massachusetts Environmental Protection Agency] waiver" (id.). Altresco's witness, Mr. Barten, stated that the assumptions used throughout the analysis were conservative and were based on industry "rules of thumb", individual expertise and data from a variety of technical publications (Tr. I, pp. 40, 41, 43).

Altresco's analysis of fuel transportation requirements for the coal and oil alternatives assumed (1) net power production of 156 MW, (2) steam flow to process at 120,000 lbs per hr, (3) capacity factors of 70 percent for coal and 75 percent for oil, (4) heat values of 12,500 Btu per lb of coal and 150,000 Btu per gallon for residual oil, and (5) an average heat rate of 10,000 Btu per kwh (id., pp. 41-42). Annual fuel requirements for the project based on these assumptions would be 400,000 tons of coal and 70 million gallons of oil, as opposed to expectations of 11 billion cubic feet ("BCF") of natural gas (Exh. HO-1, p. 4-5).

The Company indicated that coal and oil would be transported to the GE-Pittsfield complex using an existing railroad corridor and 100-ton coal gondolas or 20,000-gallon oil tankers, respectively (id. pp. 4-6, 4-7). Thus, Altresco estimated that the coal alternative would require deliveries of about 4,000 coal gondolas, while the oil alternative would require delivery of about 3,500 oil tankers per year (id.). Altresco indicated that a new 11.5-mile gas pipeline would need to be constructed southward from Pittsfield to the interstate pipeline system (Tr. 1, p. 12; Tr. 4, pp. 91; Exhs. A-10a, HO-35). In addition, the Company would need to receive delivery of rail or truck oil tankers when the proposed dual-fuel project burns oil (Exhs. HO-1, p. 6-18, HO-O-1, HO-O-3). Clearly, the environmental impacts of constructing an entirely new 11.5-mile gas pipeline would be far greater than the impacts of using an existing railroad track for coal or oil delivery.

Altresco's analysis of land requirements for the coal and oil alternatives assumed (1) 90 days storage of coal (100,000 tons) on five acres, (2) 30 days storage of oil (6,000,000 gallons) on two acres, and (3) additional space for boilers, steam turbines, additional cooling towers, flue gas cleaning equipment, and coal handling areas (Exh. HO-1, pp. 4-5 to 4-7). Mr. Barten stated that the areas required for the backup storage of 90 days of coal and 30 days of oil are reflective of industry standards and are necessary as insurance against labor problems which could affect supply (Tr. I, pp. 44-45). These assumptions resulted in total land requirement estimates of 15 acres for the coal alternative and ten acres for the oil alternative (Exh. HO-1, p. 4-6). Altresco contrasted these estimates with the five acres of land required for the proposed project (id.). Thus, while Altresco did not address the possibility of siting an oil or coal alternative within the 300-acre GE-Pittsfield complex, the proposed project would nevertheless require less land than the alternatives.

In regard to air quality, Altresco estimated emissions for the coal and oil alternatives assuming the use of both Best Available Control Technology ("BACT") and LAER control technologies[9] and compared the emissions to estimates for the proposed project (Exh. HO-8; Tr. I, pp. 47-52). The Company estimated that emissions from the proposed project would be lower than those of the alternatives in the three major categories -- SO_2, NO_x, and particulates (see Table 3 herein). Altresco did not include impacts associated with the partial use of oil in the proposed project emission estimates; this, however,

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9/ For further discussion regarding pertinent emission regulations, including requirements for use of BACT and LEAR, see Section III.E.1 infra.

would only tend to have an impact on the proposed project's SO_2 levels which are substantially lower than the SO_2 levels from the alternatives. Emissions of carbon monoxide and non-methane hydrocarbons from the coal alternative would be slightly less than similar emissions from the proposed project, but, on balance, total emissions from the proposed project with SCR would be substantially less than emissions from the alternatives (Exh. HO-8).

In regard to water supply and waste-water discharge, Altresco stated that both the coal and oil alternatives would require three times the water supply as the proposed project, and would generate approximately twice the waste-water discharge of the proposed project (Exh. HO-1, pp. 4-8, 4-9). For both the coal and oil alternatives, the additional water requirements would be due to the use of a conventional full steam cycle with power generation from steam turbines as opposed to combustion turbines, resulting in evaporative losses four times greater than those of the proposed project (id.). The coal and oil alternatives also would result in additional waste-water discharge due to greater boiler and cooling tower waste streams, and, in the case of the coal alternative, coal pile precipitation runoff requiring on-site treatment (id.). Hence, the proposed project is superior to the coal and oil alternatives in terms of water supply and waste-water discharge impacts.

In regard to liquid and solid wastes which would require removal by truck for landfill disposal, Mr. Adams stated that all wastes generated by the proposed project would be generated by the alternatives as well (Tr. 1, pp. 59-62). Altresco asserted, however, that the coal and oil alternatives would generate other wastes that would not be generated by a gas-fired project (Exh. HO-1, pp. 4-9, 4-10). Specifically, flue-gas cleaning solid waste byproducts and particulate removal would amount to 90,000 TPY for the coal alternative and 45,000 TPY for the oil alternative (id.). Therefore, the proposed project would create fewer solid and liquid wastes than a coal or oil alternative.

Based on the foregoing, the Siting Council finds that the proposed project is superior to the coal and oil alternatives with respect to environmental impacts.

5. Project Viability

a. Introduction

The Siting Council has determined that a proposed QF project is likely to be viable as a source of energy over time if (1) the project is reasonably likely to be financed and constructed so that the project will actually go into service as planned, and (2) the project is likely to operate and be a reliable, least cost source of energy over the life of its power sales agreements. NEA, supra, at 380.

In order to meet the first test of viability, the Company must establish (1) that the project is financiable, and (2) that the project is likely to be constructed within applicable time frames and capable of meeting performance objectives. In order to meet the second test of viability, the Company must establish (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that the proponent's fuel acquisition strategy reasonably ensures low-cost, reliable energy resources over the terms of the power sales agreements.

In this case, Altresco asserts that its proposed project meets these tests and, therefore, would be a viable source of energy over time (Exh. HO-1, p. 4-11; Initial Brief, pp. 20-22).

b. Financiability and Construction

Altresco presented several pro forma balance sheets to establish the economic viability of the project under a wide variety of scenarios including variations in megawatts sold, fuel supplies, and transportation costs (Exhs. A-3b, A-4, HO-24, HO-25, HO-26, HO-27, HO-28, HO-29). Altresco asserts that these balance sheets show that with only 100 MW sold the project would be economically viable, with coverage ratios between 1.5 and 1.6 based on an equity investment of 20 percent (Initial Brief, p. 21). Altresco stated that, assuming sales of all the unsold capacity to EUA, MECo, or other utilities on an avoided cost basis, the pro forma balance sheets project an exceptionally strong financial picture, with coverage ratios in excess of 2.0 (id.).

The Company's financial witness, Merrill Ring, stated that he had reviewed numerous pro formas for the project and had concluded that, with 100 MW sold, the project was financiable with full senior debt financing, while with somewhat less than 100 MW sold, the project would require some subordinated debt participation (Tr. 5, p. 17). Mr. Ring also stated that he had identified a prospective subordinated debt participant for at least $30 million which would allow financing with a coverage ratio as low as 1.3 (id., pp. 11-12).

Mr. Ring further stated that "the project is financiable based on indications of interest both on the part of the lenders and principal equity investors" (Tr. 5, p. 7). In regard to additional events which must take place before the financing could be completed, Mr. Ring stated that, with the exception of Siting Council approval, "the last and critical remaining item ... is obtaining satisfactory gas supply and gas transportation contracts" (id., p. 8). However, Mr. Ring stated that completion of financing by the MECo financing milestone date of August 15, 1988, was probable (id.).

In regard to the gas supply and gas transportation contracts, Mr. Ring stated that the lenders wanted to see interruptible domestic supply and transportation arrangements based on existing facilities which would allow the project to meet its 100 MW MECo commitment until 365 days per year of firm transportation of Canadian gas is possible (id., pp. 13-16).

In the event that full financing does not occur by August 15, 1988, and MECo terminates the 1989 100 MW PPA, leaving only the 1991 PPA for 25 MW, Mr. Ring stated that the project could not be financed (id., p. 17). However, he also stated that it would take no longer than an additional six months to develop the combination of additional power sales and full subordinated debt financing required to maintain project viability (id., p. 12). Altresco argues that the likelihood of MECo terminating its 100 MW PPA is extremely small (Initial Brief, pp. 47-48). Specifically, Altresco stated that "the testimony of the MECo witness demonstrates a strong commitment to the Altresco project and indicates a measure of flexibility in implementing Article III" (id., p. 48).[10]

In reviewing the economic viability of a proposed generating project, it is essential that the Siting Council address reasonable contingencies that could affect a project's financiability. In this case, the Company has presented a MECo witness who has underscored the utility's commitment to the 1989 PPA, as well as a financial witness who expressed confidence in the project in the event that the 1989 PPA is terminated. Accordingly, the Siting Council finds that Altresco has established that its proposed project is financiable.

In regard to the likelihood of timely construction of the project and the project's ability to meet performance objectives, Altresco presented a signed agreement with Fluor Daniel, Inc. ("Fluor Daniel") for the design, construction, and start-up of the project (Exh. HO-GE-1b). The Fluor Daniel contract includes a fixed price, subject to adjustments in costs of allowance items and change orders requested by Altresco (id.). The contract also calls for a 22-month schedule, but Altresco stated that this schedule includes "front end" engineering work which has already commenced (Tr. 3, pp. 70-75; Tr. 4, pp. 21-24). Altresco stated that actual construction should take 15 months (id.). The Fluor Daniel contract includes provisions for performance guaranties which must be met before operational conformance is demonstrated (Exh. HO-GE-1b). The contract includes both financial penalties for failure to meet the schedule and incentives for completion ahead of schedule (id.). Altresco presented documentation to show Fluor Daniel's experience in the design and construction of projects similar to the proposal (Exh. HO-B-5b).

Based on the foregoing, the Siting Council finds that Altresco's signed agreement with Fluor Daniel for the design and construction of the project provides reasonable assurances that the project is likely to be constructed on schedule and able to perform as expected.

10/ Article III of the 1989 PPA outlines certain project milestones (see Exh. HO-1, Appendix C).

In that Altresco has established (1) that the proposed project is financiable, and (2) that the proposed project is likely to be constructed on schedule and able to perform as expected, the Siting Council finds that the Company has met the first test of viability.

c. Operations and Fuel Acquisition

In regard to the operation of the project, Altresco stated that proper operation and maintenance ("O&M") of the facility would be assured through a six-year contract with General Electric-Schenectady ("GE-S") (Exh. HO-1, pp. 1-3, 4-11). The signed contract, presented to the Siting Council on August 3, 1988, requires GE-S to provide both mobilization phase and operations phase services (Exh. A-5c). Mobilization phase services would include hiring and training of plant personnel, and O&M of the facility through start-up (id.). The mobilization phase would begin 11 months prior to the projected date of operational conformance as defined in the Fluor Daniel construction agreement (id.). Operations phase services would commence on the day immediately following completion of mobilization phase services, and would include operation of the facility in accordance with the contract, performance of planned and unplanned maintenance as required, and recommendation and implementation of facility modifications (id.). Altresco also presented documentation to show GE-S's experience in the O&M of projects similar to the proposal (Exh. HO-B-12).

The O&M contract requires the use of three GE combustion turbine generators ("CT-G") and one GE steam turbine generator ("ST-G") (Exh. A-5c). The contract also indicates that bonus payments would occur for performance above target availability, but does not include any fincancial penalties for performance below target levels (id.). However, the contract does allow Altresco to terminate the contract if performance is below target levels for two consecutive years (id.).

In determining whether a QF project is viable as a reliable, least cost source of energy over the life of power sales agreements, the Siting Council evaluates the ability of the project proponent or other responsible entities to operate and maintain the facility in a manner which ensures a reliable energy supply. In a case where the proponent has relatively little experience in the development and operation of major energy facilities, that proponent must establish that experienced and competent entities are contracted, or otherwise committed, to perform critical tasks. These tasks should be set out pursuant to detailed contracts or other agreements that include financial incentives and/or penalties which ensure reliable performance over the life of the power sales agreements.

While an applicant is not required to demonstrate that it has experience in power plant operation as a prerequisite for establishing viability, endorsement of this project by the Siting Council without either a "track record" in the operation of major generating facilities, or a committed O&M participant, would be tantamount to issuing a "blank check" to the applicant. Issuance of such a blank check would be entirely inconsistent with the Siting Council's mandate to ensure a reliable energy supply.

Here, neither the applicant nor its parent company has demonstrated the necessary experience in the operation of major generating facilities. However, the O&M contract between Altresco and GE-S, an experienced facility operator, contains sufficient detail to assure the Siting Council that the project is likely to be operated and maintained in a manner consistent with reliable performance over the life of the power sales argreements.

Accordingly, the Siting Council finds that the Company has established that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives.

In regard to its fuel acquisition strategy, Altresco presented (1) a signed contract with Vector Energy, Inc. ("Vector") for a 20-year supply of natural gas volumes at 26,500 MMBTU per day firm and 3,500 MMBTU per day interruptible, (2) a signed letter of intent from Wainoco Oil Corporation ("Wainoco") to enter into a contract with Altresco for a 20-year firm supply of natural gas volumes at 5 MMCF (approximately 5,000 MMBTU) per day, and (3) a letter of interest from Placer Cego Petroleum to contract with Altresco for the supply of 5 MMCF based on terms and conditions to be considered (Exhs. A-9, A-19, HO-G-4a; Tr. 4, pp. 96-97). The Vector contract states that Vector would act as pool manager for six suppliers, and includes assurances that, should any of the six suppliers be unable to provide its portion of the total volumes on a given day, the remainder of the suppliers would cover the shortfall (id.). Additionally, should any other suppliers to Altresco be unable to meet their commitments on any given day, the contract calls for Vector to use best efforts to cover any resulting shortfall (id.).

Altresco's witness, Barry Curtis-Lusher, testified that the combination of the three Canadian gas sources represents the full volumes needed for the facility, and that the Vector agreement would ensure coverage of any shortfalls in the event that either of the other two companies is unable to fulfill their obligations (Tr. 4, p. 86). Mr. Curtis-Lusher further stated that contract negotiations with Wainoco and Placer Cego were based on the same format as the Vector contract. The Vector contract provides for firm supplies to be delivered subject to availability of pipeline transportation (Tr. 4, p. 87; Exh. A-19). Mr. Curtis-Lusher also noted that the contract with Vector includes the same price index that is included in the MECo contract, thereby ensuring protection for Altresco in the event of fuel cost escalation (Exh. HO-1, Appendix C; Exh. A-19; Tr. 3, pp. 40-41). This fuel cost escalator is tied to a basket of fuels including oil, natural gas and coal and ensures that revenues from power sales would reflect changes in fuel costs (id.). The Vector contract also allows Altresco to reduce its volumes over time if more cost effective supplies become available (Exh. A-19).

Altresco stated that it intends to transport the Canadian volumes across Canada to Tennessee Gas Pipeline Company's ("Tennessee") Niagara spur, and then through various portions of the Tennessee and CNG Transmission Corporation ("CNG") interstate systems (Exhs. HO-1, pp. 2-7, 2-8, HO-G-4, HO-G-12, HO-G-13). From a point on the Tennessee main line, the volumes would be transported northward to Altresco by a proposed 11.5-mile pipeline to be constructed by Berkshire, or a similar line to be constructed by Tennessee (id.). The Company concedes that significant pipeline expansion in both Canada and the United States must be approved[11] and constructed before Altresco's firm volumes from Canada can be transported from points of origin to the Tennessee main line (id.).

In the event that year-round firm Canadian gas supplies are delayed, Mr. Curtis-Lusher testified that Altresco is negotiating with three U.S. suppliers -- Diversified Energies, Enron Gas, and Cabot Energy -- for interruptible gas (Tr. 4, pp. 89-90). According to Mr. Curtis-Lusher, these interruptible supplies, in combination with Canadian supplies when available, would ensure at least 300 days of gas supplies per year, while additional peak supplies could be provided by Distrigas of Massachusetts (id.). If these backup supplies are curtailed for any reason, Altresco states that it would burn distillate oil up to maximum levels allowed under applicable emission limits (Exh. HO-G-9).

In regard to the the Company's plans for transportation from the Tennessee main line to the project site, Altresco noted that it has reached preliminary agreement with Berkshire for the construction of the pipeline (Tr. 4, pp. 91-92; Exh. A-10a). Under this agreement, the line would be paid for by Altresco, and designed, constructed, maintained and owned by Berkshire (id.). If Berkshire were unable to obtain the necessary permits and approvals to construct the 11.5-mile line,[12] Altresco stated that Tennessee would most likely file an application with FERC to construct a similar line apart from the ongoing Open Season proceedings (Tr. 4, pp. 111-112). However, this option would be considerably more costly (Exh. HO-35). If completion of a pipeline by either Berkshire or Tennessee is delayed beyond the commencement date of

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11/ Pipeline expansion in the Northeast United States is currently being addressed by FERC as part of its "Open Season" proceeding (FERC Docket CP87-451-000). While there are no Open Season applications that specifically include sales or transportation to Altresco, the Company asserts that it has assurances from both Tennessee and CNG that necessary facilities for the project would result from resolution of Open Season proceedings (Exh. HO-G-12).

12/ The construction of an 11.5-mile pipeline by Berkshire would require the Siting Council's approval.

project operation, Altresco asserted that sufficient supplies to meet the MECo contract would be available through the existing Berkshire system (Tr. 4, pp. 112-114; Exhs. HO-30, HO-31).

In considering an applicant's fuel acquisition strategy, the Siting Council addresses the reliability, flexibility, and price stability of fuel supply and transportation arrangements. In this case, Altresco has developed a comprehensive strategy for fuel supply and transportation which considers a wide range of options and contingencies. In regard to fuel supply, Altresco has arranged for firm Canadian volumes from a variety of suppliers, pursuant to a contract which ensures price stability while allowing Altresco to reduce volumes when lower cost alternatives are available. Further, the Company has presented various options for obtaining interruptible supply in the event that adequate year-round transportation of the Canadian volumes is not available as of commencement of operation.

In regard to fuel transportation, the Company has presented its plans for securing adequate transportation to the project site. These plans, however, consist of various transportation options which require federal or state approval. While the Company's strategy for fuel transportation includes some measure of uncertainty, the Siting Council recognizes that QF's, as well as other gas purchasers, are presently competing for limited gas transportation. Until such time as FERC concludes its Open Season proceedings, it is unrealistic for the Siting Council to expect an applicant to present concrete gas transportation arrangements. In recognizing this constraint in its review of project viability, the Siting Council underscores its support for the development of cost-effective QF resources that provide reliable energy resources and minimize environmental impacts.

Based on the foregoing, the Siting Council finds that Altresco has shown its fuel acquisition strategy ensures low cost reliable energy over the terms of its power sales agreements.

In that Altresco has established (1) that the project is likely to be operated and maintained in a manner consistent with appropriate performance objectives, and (2) that its fuel acquisition strategy ensures low cost reliable energy resources over the terms of its power sales agreements, the Siting Council finds that the Company has met the second test of viability.

d. Conclusions on Viability

The Siting Council has found, in Section II.B.5.b, above, that Altresco has demonstrated that its project is reasonably likely to be financed and constructed. In Section II.B.5.c, above, the Siting Council has found that Altresco's project is likely to meet appropriate operational performance objectives, and that its fuel acquisition strategy reasonably ensures low-cost, reliable energy resources. Accordingly, the Siting Council finds that the proposed project is likely to be viable as a source of energy over time.

6. Conclusion on Proposed Project and Alternate Approaches

The Siting Council finds that (1) the proposed project is superior to a reasonable range of practical alternatives with respect to addressing the identified need, (2) the proposed project is superior to a reasonable range of practical alternatives in terms of cost and offers power at a cost below the purchasing utility's avoided cost, (3) the proposed project is superior to a reasonable range of practical alternatives in terms of environmental impacts, and (4) the proposed project is likely to be viable as a source of energy over time. In sum, the Siting Council has determined that Altresco's proposed project is economically and environmentally superior to alternatives, and is likely to produce needed electricity such that ratepayers' electricity costs are lower than what they would otherwise be in the absence of the project.

Accordingly, the Siting Council finds that Altresco has demonstrated that its project is consistent with ensuring a necessary energy supply with minimum impact on the environment at lowest possible cost.

III. ANALYSIS OF THE PROPOSED FACILITIES

A. Standard of Review

G.L. c. 164, sec. 69I, requires a facility proponent to provide information regarding "other site locations." In implementing this statutory mandate, the Siting Council requires the petitioner to show that its proposed facilities siting plans are superior to alternatives. Specifically, a petitioner must demonstrate that its proposed facilities are sited at locations that minimize costs and environmental impacts while ensuring supply reliability.

In previous cases, once the Siting Council has determined (a) that new energy resources are needed, and (b) that the applicant has proposed a project that is, on balance, superior to alternative approaches in terms of cost, environmental impacts, and meeting identified need, the Siting Council has required the petitioner to show (1) that it has examined a reasonable range of practical facility siting alternatives, and (2) that the proposed site for the facility is superior to the alternative site(s) on the basis of a balancing of cost, environmental impact, and reliability of supply.[13] NEA, supra at 381-409; Cambridge Electric Light Company, supra, at 195-196, 229-237; Hingham Municipal Lighting Plant, supra, at 22-32; Massachusetts Electric Company, supra, at 183-184, 190-248; Boston Edison Company, supra, 67-68, 76-81.

B. Description of the Proposed Facilities and Alternatives

1. Proposed Facilities

As indicated above, Altresco proposes to construct (1) a nominal 160 MW combustion turbine, combined-cycle cogeneration facility, and

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13/ In light of the Siting Council's findings in Section III.C, infra, reliability of supply is not addressed in this decision.

(2) ancillary facilities necessary for emergency backup fuel oil delivery and storage, and electric power transmission. The proposal does not include any ancillary facilities for the transportation of the primary fuel, natural gas (see Section I.A, supra).

The Company proposes to construct these facilities entirely within a 4.9-acre industrially-zoned site within the GE-Pittsfield complex (see Figure 1 herein). The site area is well above the 100-year floodplain of the Housatonic River, and there are no resource areas (as defined by the Massachusetts Wetlands Protection Act and MDEQE regulations) on the project site (Exh. HO-1, Appendix A, pp. 1-2 to 1-10). Altresco provided correspondance from the Massachusetts Natural Heritage Program in support of the position that there are no rare plants or animals in the site area (id.).

Altresco's proposed generating facility is a topping-cycle[14] cogenerator consisting of three dual-fuel General Electric Frame 6 CT-Gs with nominal capacities of 40 MW each, three unfired natural circulation heat recovery steam generators, and one 46 MW automatic extraction condensing ST-G (Exh. HO-1, Appendix A, pp. 1-11 to 1-12, and Appendix E). High and intermediate pressure steam will be provided to the GE-Pittsfield complex for process and heating uses, thereby requiring construction of steam and condensate return lines between the plant and the GE-Pittsfield complex (Exh. HO-1, pp. 2-5, 2-26). These lines would run to various buildings within the complex to both the east and west of the proposed facility via a combination of new and existing above-ground piperacks entirely within the complex (id.). Additional components of the facility include three 125-foot high emission stacks, a five-cell wet mechanical draft cooling tower for condenser cooling, fuel gas compressors, and a 115 kV switchyard (id., pp. 2-2, 2-19). The facility will incorporate steam injection in combination with SCR to maintain facility emissions at a level consistent with LAER (id., p. 5-6).

14/ 18 CFR 292.202 defines a topping-cycle cogeneration facility as "a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy."

The 115 kV transmission line would connect the plant with an existing 115 kV substation located on the GE-Pittsfield property approximately 600 feet to the west of the proposed site (Exhs. HO-1, p. 2-10, HO-E-14). This substation is owned and operated by Western Massachusetts Electric Company ("WMECo"), who would provide transmission capacity for wheeling the power to Altresco's electric customers. Altresco has indicated that the proposed transmission line will be entirely on unoccupied GE-Pittsfield property (Exh. HO-1, pp. 2-10, 2-23).

The Company presented the results of a study performed by Northeast Utilities ("NU") for Altresco which describe two options for the upgrading of the bulk power transmission facilities from the substation on the GE-Pittsfield property to NU's Doreen substation (Exhs. A-6, HO-22). Altresco would be responsible for all costs under both options (id.). Altresco has stated that it intends to contract with NU, through WMECo, for the more expensive option, which would consist of rebuilding and reconductoring, as necessary, the existing 115 kV transmission line from GE-Pittsfield to the Doreen substation, in addition to making substation improvements at both locations (Tr. 4, pp. 15-17). Upon notice to proceed from Altresco, WMECo expects that interconnection could be completed within 16 months (id.). Altresco maintaines that additional modificaton of WMECo's transmission system beyond the Doreen substation would be unnecessary (Initial Brief, p. 4).

The proposed fuel oil storage facilities would consist of a 500,000-gallon oil storage "day tank" at the proposed site (Exh. HO-O-3). Additional fuel oil storage, consisting of three existing 500,000-gallon tanks would be available at the west end of the GE-Pittsfild complex (id.). These tanks currently are used for residual oil storage for the existing steam plant and will be emptied and cleaned for use by Altresco when that steam plant is decommissioned (id.).

Fuel oil delivery facilities would include oil pipelines to connect the oil storage tanks (new and existing) to the facility (Exh. HO-1, p. 2-9). Altresco stated that these pipelines would run above ground on approximately 1500 feet of new piperacks in addition to existing piperacks primarily to the west of the plant and within the

GE-Pittsfield complex (steam and condenstate return lines would likely utilize the same piperacks) (id.).

Altresco stated that it would prefer that railroad tankers provide transportation of emergency backup fuel oil to the site, but transportation by a combination of rail and truck tankers would be more likely and appropriate (Exh. HO-O-3). Rail tanker off-loading facilities exist at the GE-Pittsfield complex, and are currently used when filling the existing storage tanks (id.). A temporary transfer pumping station would be installed to move fuel oil from these existing tanks to the day tank at the cogeneration plant site (id.). Altresco stated that it is considering installation of a truck tanker off-loading facility to allow transportation of fuel oil by truck tankers (id.).

The project is currently scheduled for an accelerated 15-month construction period which would enable the plant to meet MECo's desired December 1, 1989, on-line date (Tr. 3, p. 75; Tr. 4, pp. 19-24). This schedule is dependent upon performance of substantial pre-construction engineering and design work by Fluor Daniel which has already commenced (id.; Exhs. HO-19, HO-23). The construction work force is expected to average 80 workers and the facility is expected to employ 22 persons once in operation (Exh. HO-1, p. 2-14).

2. Alternatives

Altresco identified a total of six sites (see Figure 1) within the GE-Pittsfield complex as possible locations for the proposed facilities (see section III.C, infra). Altresco indicated that, with the exception of plant layout differences, the generating facility would be the same at each of the six sites; ancillary facilities however, would be different for each site (Exh. HO-1, pp. 5-1 to 5-8).

The specific sites selected were (1) Alternate Site A, a parcel including the existing steam plant at the west end of the complex; (2) Alternate Site B, a parcel of elevated land to the east of New York Avenue adjoining GE-Pittsfield's licensed hazardous waste storage and treatment area; (3) Alternate Site C, a parcel at the corner of New York Avenue and Merrill Road; (4) Alternate Site D, a parcel near the center of a relatively unused area of the complex currently used for disposal of fill from GE construction projects; (5) Site E, the proposed site, adjacent and to the east of Alternate Site D; and (6) Alternate Site F, a paved area currently used as the parking area for GE-Pittsfield's Ordnance Plant (id., p. 5-3).

If one of the five alternate sites were utilized, the length and routing of the transmission line, fuel oil delivery line, and steam and condensated return lines would be different from the lengths and routes required for the proposed site. Location of the fuel oil day tank, truck tanker off-loading facility, and need for and location of the temporary transfer pumping station also would be different. Additionally, site preparation, permitting, and construction schedules would differ (id.; Exh. HO-A-2). While the record in this proceeding does include these specific details of the ancillary facilities for the alternate sites, Altresco has indicated that all facilities for any of the sites would be within the GE-Pittsfield complex (see Figure 1).

C. Site Selection Process

Altresco presented a detailed description of the process and criteria used to select a steam host, to propose a site for the proposed facilities, and to identify alternative sites (Exh. HO-1, pp. 5-1 to 5-3).

Altresco stated that, after identifying Massachusetts as a region of interest for investment in energy facilities, it identified GE-Pittsfield as a potential purchaser of quantities of steam sufficient to warrant a sizeable cogeneration facility (Exhs. HO-1, p. 5-1, HO-A-1). Altresco determined that GE-Pittsfield represented an ideal steam host based on the criteria of steam demand, financial strength and stability, and location (id.). Altresco provided that location advantages include available land, access to the electric transmission grid, access to gas transmission, and a water supply (id.).

The Company recounted that, once it had established GE-Pittsfield as the candidate steam host, engineers from these two companies jointly determined the facility size and design provisions that would ensure a reliable, cost-effective steam supply for GE-Pittsfield as well as financial viability for Altresco (Exh. HO-1, pp. 5-1 to 5-3). Next, Altresco specified evaluation criteria for screening potential sites including,

- o site size,
- o zoning and land use,
- o time required to acquire land,
- o length required for steam and condensate-return lines to the GE-Pittsfield complex, and
- o presence of floodplains or sensitive resources such as wetlands (id.).

Based on these criteria, Altresco screened the area surrounding the GE-Pittsfield complex, determining that the 300-acre complex provided the only suitable sites for the proposed facilities (id.). Within the GE-Pittsfield complex Altresco identified six potential sites as described above (id.). However, Altresco eliminated Alternate Sites A, B, C, and F based on space constraints, present land use, and length of steam and condensate-return lines (id.). Hence, Altresco determined that only the two remaining sites -- the proposed site (Site E) and Alternate Site D -- would be practical alternatives for its plant siting (id.).

G.L. c. 164, sec. 69I, requires consideration of at least one practical facility siting alternative (see Section III.A, supra). In past cases, in order to determine that a facility proponent has considered a reasonable range of practical facility siting alternatives, the Siting Council typically has required the proponent to establish (1) that it has developed and applied a reasonable set of criteria for identifying alternatives, and (2) that it has identified at least two practical sites with some measure of geographic diversity. Middleborough Gas and Electric Department, EFSC 87-18 (1988); Commonwealth Electric Company, EFSC 85-4A (1988).

In regard to the first requirement, the Siting Council finds that Altresco has developed a reasonable set of criteria for identifying alternatives. Here, Altresco has identified one candidate steam purchaser, GE-Pittsfield, which has several project development advantages, including significant steam demand, financial strength and stability, available land for facility siting, and a location with access to electric transmission and water supply. In essence, these project development advantages represent the overall criteria for project siting. As such, Altresco has developed site selection criteria that are appropriate for identifying sites that minimize the economic costs and environmental impacts of constructing and operating needed energy facilities.

The Siting Council also finds that Altresco has appropriately applied its criteria for identifying alternatives. In this case, Altresco has identified six sites, five of which are clustered in the central-east section of the GE-Pittsfield complex and one which is at the west end of the complex (see Figure 1). The record in this case demonstrates that Alternate Sites A, B, C, and F present development disadvantages: space constraints, present land use, and the increased length of steam and condensate-return lines -- which render them impractical and justify their elimination from further consideration.

The Siting Council, however, cannot find that Altresco has fulfilled its second requirement -- identifying at least two practical sites with some measure of geographic diversity. Here, Altresco has proposed a site and alternative that are located only a few hundred feet apart and, in fact, overlap to some degree (see Figure 1). Such a small difference between the sites raises the question as to whether the proposed site and the alternate site (Alternate Site D) represent true alternative site choices, as opposed to design optimization within one larger site. The record indicates that, indeed, the proposed site and Alternate Site D are effectively two sections of a larger site and, as such, do not represent practical facility siting alternatives.

At the same time, the Siting Council recognizes Altresco's unique position as the proponent of a cogeneration facility. Economics generally require a cogenerator to be in close proximity to its steam purchaser(s). In cases where the steam purchaser(s) is known, the location of the purchaser or purchasers may predetermine the general vicinity of the cogenerator. Further, where known steam purchasers offer clear and certain project advantages, such as significant steam demand or available land for siting, those advantages may preclude practical siting alternatives.

Therefore, in cases involving proposals to construct cogeneration facilities, if the facility proponent can establish that a second practical facility site does not exist, the Siting Council does not require the identification of two geographically diverse sites. In that GE-Pittsfield is a steam purchaser that (1) is known, (2) has significant steam demand, and (3) has land available for facility siting, Altresco has established that practical alternatives to the proposed facility site do not exist.

In sum, the Siting Council has found that Altresco has established (1) that it has developed and applied a reasonable set of criteria for identifying alternatives, and (2) that practical facility site alternatives to the proposed site do not exist.[15] Accordingly, the Siting Council finds that the Company has considered a reasonable range of practical facility siting alternatives.

D. Cost Analysis of the Proposed Facilities

Although Altresco has established that there are no practical alternatives to its proposed site (see Section III.C, supra), the Siting Council nevertheless must determine whether the proposed facilities are

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15/ Although the Company has established that alternatives to the proposed site do not exist, the Siting Council discusses certain cost and environmental impacts of Alternate Site D in the context of the Siting Council's review of the cost and environmental impacts of the proposed facility (see Section III.D, infra).

consistent with ensuring a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. Therefore, the Siting Council evaluates the proposed facilities to determine whether the costs associated with construction are acceptable.

Altresco estimated that its investment in the proposed facilities would total $151 million of which $110 million would be for plant construction costs, $11 million for development costs, $19 million for interest during construction and loan fees less escrow interest, and $11 million for contingencies (Exh. HO-1, p. 2-12).

Altresco's siting of its proposed facilities on land owned by GE-Pittsfield provides both direct and indirect cost benefits. First, Altresco negotiated a 99-year property lease with GE-Pittsfield for a total rental fee of $1.00 (Exh. HO-GE-3). This arrangement provides Altresco with long-term stability in its land arrangements at virtually no cost. The central location on the GE-Pittsfield complex helps minimize the length of costly steam and condensate-return lines. Another direct benefit of siting on GE-Pittsfield land is the ability to maximize use of the existing infrastructure including oil storage tanks, an oil pipeline, and steam and condensate-return lines.

The GE-Pittsfield location also minimizes electric transmission construction costs since Altresco proposes to tap into the transmission grid at a point only 600 feet from the proposed site (Exhs. HO-1, p. 2-10, HO-E-14). However, Altresco's original estimate that 2,500 feet of pipeline would be sufficient to provide a tie into the interstate gas pipeline lateral proved incorrect. Altresco later stated that approximately 11.5 miles of pipeline construction would be necessary in order to connect with the main interstate pipeline network (Exh. HO-35). Even so, the Company contended that pipeline construction costs would be minimized by arranging to have Berkshire construct and own the pipeline rather than Tennessee (id.). According to Altresco, its gas transportation arrangement with Berkshire could reduce costs by $6.5 million because it would cost Berkshire $5.0 million to construct the line, while the cost of Tennessee construction would be 11.5 million (id.).

Based on the information provided by the Company, the Siting council notes that siting of the proposed facilities on the GE-Pittsfield complex provides indirect benefits through the elimination of a land acquisition process with another party likely to have less incentive to negotiate such favorable terms. This aspect is particularly significant in light of the importance of Altresco meeting its MECo contract milestones and avoiding financial penalties or termination.

Altresco has identified and considered a variety of factors that affect the cost of siting its proposed facilities. The Company has shown that consideration of those factors has contributed to minimizing the cost of the proposed facilities. Accordingly, the Siting Council finds that the cost of the proposed facilities is acceptable.

E. Environmental Analysis of the Proposed Facilities

In the course of this proceeding, Altresco has presented a detailed analysis of the environmental impacts which would result from the construction of the proposed facilities at the proposed site. This analysis included a discussion of the extensive mitigation measures to be taken to minimize such impacts. In its review, the Siting Council determines whether the proposal would be acceptable with respect to its expected environmental impacts.[16] Boston Gas Company, EFSC 86-25A, pp. 26-31 (1988); NEA, supra at 391-407.

Potential environmental impacts identified during this proceeding were related to air quality, noise, water supply, waste-water discharge, visual effects, and safety effects. The Siting Council reviews these impacts in its analysis of the proposed facilities.

16/ Before approving proposed facilities, the Siting Council must determine that the proposed facilities are "consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." G.L. c. 164, sec. 69J.

1. Air Quality

Altresco provided that the proposed generating facility would utilize the cleanest burning fuel available, natural gas, with low sulfur distillate oil as emergency backup, and would employ state of the art control technology to reduce plant emissions and resulting air quality impacts to a level well below federal standards (Exh. HO-1, pp. 6-1 to 6-3 and Appendix A, pp. 1-1, 1-19). In addition, Altresco stated that construction of the proposed facilities would result in a net benefit to ambient air quality as a result of the retirement of the existing GE-Pittsfield boiler plant and power production displacement on the NEPOOL grid (id.).

Altresco stated that EPA New Source Performance Standards ("NSPS") would apply to the facility (id.; Tr. 1, pp. 71-73). NSPS place limits on the emissions from significant new sources. In addition, the control concepts of BACT and LAER may be required under NSPS requirements (id.). LAER is required if the new source is located in an area designated as "non-attainment" with respect to federal ambient air quality standards (id.). Altresco stated that the only non-attainment pollutants for the Pittsfield area are ozone ("O_3") and total suspended particulates ("TSP") (id.). However, Altresco stated that the facility emissions of volatile organic compounds (precursors of O_3) and TSP would be less than the threshold of 100 TPY for LAER application (id.). Therefore, Altresco provided that the facility is required only to meet the requirements of BACT (id.).

Altresco stated that it nevertheless proposes to use control technology reflective of LAER in order to reduce facility emissions to a level at which the expensive and time consuming Prevention of Significant Deterioration ("PSD") review is not required (Tr. 1, pp. 93-97; Exh. HO-1, pp. 5-6 to 5-7). Federal PSD regulations set limits of 250 TPY per regulated pollutant (Exh. HO-1, pp. 6-1 to 6-3 and Appendix A, pp. 2-2 to 2-6). Without eliminating this additional review process, Altresco provided that it would not meet its June 1990 MECo contract milestone (Initial Brief, p. 31). Altresco asserts that the use of a technology reflective of LAER has received strong support from the Massachusetts DEQE, and that this is a component of Altresco's DEQE's Air Plans and Approval process review (Exh. HO-1, p. 6-3).

Facility emissions of primary concern in meeting the applicable limits are NO_x, a significant byproduct of natural gas combustion, and SO_2 which increases substantially when burning distillate oil (Exh. HO-1, p. 6-1). Altresco provided backup documentation to support its assertion that use of SCR in combination with steam injection would reduce NO_x emissions to 9 parts per million ("ppm") during normal gas-fired operation which represents an overall reduction of approximately 95 percent based on dry combustor emission levels (i.e., combustion without SCR and steam injection) (Exhs. HO-1, pp. 6-1 to 6-3, HO-EN-6, HO-S-2, HO-S-6). In order to maintain annual SO_2 emissions below the PSD limits, Altresco noted that the DEQE Air Plans and Approval process would establish limits on both fuel sulfur content and quantity of distillate oil to be burned annually (Exh. HO-O-2).

Altresco provided dispersion modeling studies which estimated the impact on surrounding areas from the facility emissions (Exh. HO-1, pp. 6-4 to 6-6, and Appendix A, pp. 2-17 to 2-24). These studies were performed in accordance with Federal EPA and DEQE air quality screening guidance. The methods were submitted to the DEQE in June 1987, and are the basis for the Air Plans Application (id.).

Altresco used three models to estimate air quality effects (id.). The first and second models, PTPLU-2 and ISCST, represent ground level concentrations at elevations below the stack tops (i.e., below 125 feet), while the third model, VALLEY, predicts ground level concentrations for surrounding hills with elevations above the stack tops (id.). Altresco used the rural option for each model, and generated emission dispersion data for 50, 75, and 100 percent plant operation (id.). The modeling results indicated that the worst case plant impacts under either all-gas or gas-with-maximum-oil use scenarios were within the applicable air quality standards (id.). The Company's air quality witness, Mr. Neilsen, testified that Altresco used Springfield air quality data as a basis for establishing ambient conditions for use in modeling plant impact (Tr. 1, pp. 115-116). Mr. Neilsen stated that Springfield data was used due to the lack of existing data from Pittsfield, and that the Springfield data should be conservative relative to Pittsfield (i.e., worse ambient conditions relative to air quality standards) due to the larger size of Springfield and its location in the Connecticut River valley which would tend to inhibit dispersion of pollutants (id.).

Altresco's lead environmental witness, Mr. Adams, testified that the modeling was based on use of Alternate Site D (Tr. 1, pp. 133-134). Mr. Adams stated that, after consultation with the DEQE, Altresco made a determination that no significant differences would result if the analysis were redone assuming use of the proposed site since relocating the stacks only a few hundred feet would have a trivial effect on the maximum air quality impacts (id.). Therefore, Mr. Adams asserted that the air quality impacts would be essentially the same for the proposed site and Alternate Site D (id.).

In sum, the cleanest burning fuel available, the limited use of oil, and the use of SCR coupled with steam injection would significantly control emissions from the Altresco facility. The Siting Council finds that Altresco has demonstrated that, with the mitigation measures described herein, the air quality impacts which would result from the proposed facility would be acceptable.

To support its position that construction of the proposed facility would result in an overall net benefit to ambient air quality due to the retirement of the existing steam plant, Altresco compared existing emissions to those expected from the proposed facility (Exh. HO-1, p. 6-4 and Appendix A, pp. 2-12 to 2-14; Exh. HO-EN-9). The Company calculated estimates of current annual emissions from the existing plant based on 1986 fuel consumption, an average fuel sulfur content of 1.8 percent for No. 6 residual oil and 0.2 percent for No. 2 distillate oil, and typical emission factors for oil and gas firing in existing steam boilers as set forth in EPA publication AP-42, "Compilation of Air Pollutant Emission Factors" (id.). The Company's estimates of emissions from the proposed facility are based on manufacturer's data for the combustion turbines with steam injection and the SCR system (Exhs. HO-EN-6, HO-S-2, HO-S-6).

GE-Pittsfield is currently operating its steam plant under a DEQE administrative consent order which requires the plant to be shut down by January 1, 1991 (Exh. HO-EN-1). Altresco provided that construction of the proposed facilities will enable GE-Pittsfield to comply with the DEQE's condition regarding replacement of the existing boilers (Exh. HO-1, p. 2-14).

Altresco also asserted that there would be a net air quality benefit as a result of power production displacement on the NEPOOL grid (Exh. HO-1, pp. 6-3 to 6-4 and Appendix A, pp. 2-15 to 2-16). Altresco based its assertion on assumptions relating to NEPOOL dispatch hierarchy reached through discussions with NEPOOL power supply planning personnel (Exhs. HO-EN-4, HO-EN-10). The Company provided emission reduction estimates assuming 156 MW of power production displacement for 88 percent of the year, use of low sulfur oil (0.5 percent), an average heat rate of 10,000 BTU/kw-hr, and coal-fired capacity displacement on nights and weekends and oil-fired capacity displacement on weekday day and evening periods (id.; Tr. 1, pp. 82-91).

The Siting Council finds that, due to the retirement of the existing GE-Pittsfield steam plant, there will be a net positive impact on local air quality. However, in regard to the Company's assertion that additional net emissions reduction and air quality improvement will result from power production displacement in the NEPOOL grid, the Siting Council finds that Altresco has provided insufficient documentation to support the assumptions on which its argument is based. Specifically, an attempt to quantify this displacement, in the near or long term, requires numerous assumptions related to demand, reserve margins, and relative fuel costs. The Siting Council notes that these assumptions are appropriate in general discusions related to need and economic benefit, but are unacceptably imprecise when attempting to quantify environmental impacts from specific facilities.

Accordingly, the Siting Council finds that, with the mitigation measures proposed by Altresco, the proposed facilities will have an acceptable impact on air quality.

2. Noise

Altresco maintains that its proposed facilities would meet all applicable DEQE noise standards, and that it has taken all reasonable measures to minimize noise impacts (Exh. HO-1, p. 6-7).

Altresco stated that DEQE's noise standard requires that the proposed facility cannot increase ambient noise levels at surrounding sensitive receptor locations by more than 10 decibels ("dB") (Exh. HO-1, pp. 6-7 and Appendix A, p. 3-1). The existing ambient noise level at a location is defined as the background dB level which is currently exceeded 90 percent of the time during periods in which the proposed facilities would be operating (id.).

Altresco conducted an ambient noise survey in April 1987 to establish existing noise distribution at nine locations surrounding the sites during weekday day and night periods, and weekend day and night periods (Exh. HO-1, pp. 6-7 to 6-10, and Appendix A, pp. 3-1 to 3-7). In consultation with DEQE, Altresco then determined four critical receptor locations, the three closest houses and the Allendale Elementary School, and estimated noise level increases at these locations due to facility operation (id.). In determining noise increases, Altresco identified the primary sources of plant noise as combustion turbine air intakes and exhausts, rotating equipment (e.g., fans, motors), steam generator surface and piping flow turbulence, and the mechanical draft cooling towers (id.). Altresco's estimates of facility noise impacts are based on the incorporation of extensive mitigation measures in the facility design (id.). These measures include specially designed buildings, low speed fans, exhaust silencers, noise barriers, oversized cooling towers, and layout changes to provide additional shielding (id.). Mr. Adams stated that the mitigation measures proposed "are somewhat extraordinary" and reflect the proximity of sensitive receptors such as schools and residences (Tr. 2, pp. 45-46).

Assuming the proposed mitigation measures are implemented, Altresco estimated that noise level increases at the critical receptor locations due to operation of the proposed facilities at the proposed site[17] would be within the 10 dB DEQE limit and, in fact, should not exceed 7 dB (Exh. HO-1, pp. 6-8 to 6-9, and Appendix A, p. 3-7). Altresco's data indicate that during normal school hours there would be no audible impact at the Allendale Elementary School as a result of facility operation (id., p. 6-9).

The Siting Council finds that the Company has provided adequate support for its position that noise impacts from the facilities would meet applicable limits, and that the Company's use of extensive mitigation measures would help to minimize noise impacts. Accordingly, the Siting Council finds that, with Altresco's proposed mitigation measures, operation of the proposed facilities would have an acceptable impact on community noise levels.

3. Water Supply

Altresco maintains that adequate water supplies exist for facility operation without adverse impact on Pittsfield's city water system or local groundwater resources (Initial Brief, p. 35).

Altresco anticipates that the proposed generating facility would require a net water supply of approximately 1.4 million gallons per day ("MGD") (Exh. HO-1, p. 6-11). Altresco stated that the water primarily is needed for cooling tower makeup, combustion turbine steam injection for NO_x control, and condensate makeup (id.). Additional water is required for demineralizer regeneration, boiler blowdown, filtration, potable water, and turbine wash (id.). The net demand of 1.4 MGD includes the elimination of the 0.12 MGD water demand for GE-Pittsfield's existing steam plant (id., p. 6-12).

17/ Altresco provided a quantitative estimate of the noise impact at the critical receptors which would result if the facilities were built on the alternate site (Exh. A-1). These data indicate that, should the alternate site be used, there would be no difference at two of the receptors (including the Allendale Elementary School), a decrease in the impact at one and an increase in the impact at the other (id.). However, the impact at all four receptors would still meet the 10 dB DEQE limit on noise increases.

Altresco stated that approximately half of the necessary water requirements would be met through the use of a well on GE-Pittsfield property, while the balance would be supplied by the Pittsfield city system (Exh. HO-B-15).[18] Altresco submitted documents relating to the delivery capability and quality of the existing well as well as an analysis of the Pittsfield system, which together establish the ability of the sources to meet the demand (Exhs. HO-1, pp. 6-13 to 6-15 and Appendix A, pp. 4-7 to 4-16; HO-PP-5). Altresco stated that the facility's total water demand represents approximately 40 percent of the total reduction in City water use which has occurred at the GE-Pittsfield complex in the last several years. The Company asserts therefore, that the Pittsfield city water system is capable of supplying the entire facility need if necessary (Exh. HO-1, pp. 6-13 to 6-15).

Mr. Adams stated that water pipelines for the well supply would cross only GE-Pittsfield property, with the possible exception of crossing New York Avenue (Tr. 1, pp. 8 - 9). In addition, Altresco plans to analyze the costs and benefits of drilling a new well as opposed to using an existing well (id., pp. 7 - 10). Any well, however, would be part of the Housatonic River water shed and would require a permit for withdrawal in accordance with the State Water Management Act (id.). Finally, Altresco noted that there are no public or private wells in the immediate area which would be affected by drawing upon either the existing or a new well (id., p. 22).

The Siting Council finds that Altresco has provided sufficient documentation in support of its position that adequate water supplies exist to support operation of the proposed facilities without adverse impact to the local water resources. Accordingly, the Siting Council finds that the proposed facilities would have an acceptable impact upon Pittsfield's water supply.

18/ In its filing, Altresco anticipated use of this well on a backup basis only (Exh. HO-1, p. 6-15). However, in response to potential concerns on the part of Pittsfield city officals, Altresco decided to utilize this well on a regular basis (Tr. 2, pp. 5-6).

4. Waste-Water Discharge

Altresco stated that the proposed generating facility would discharge waste-water into the City sewer system at an average flowrate of approximately 109,000 gallons per day ("gpd") (Exh. HO-1, pp. 6-15 to 6-16, and Appendix A, pp. 4-16 to 4-17).[19] The Company asserts that the Pittsfield city sewer system could absorb this increase in flow without any adverse effects (Exh. HO-1, p. 6-16, and Appendix A, pp. 4-16 to 4-23, 4-25 - 4-27). In support of its position, Altresco provided a recent inflow/infiltration study performed by the Pittfield (Exh. HO-PP-4). This study indicated that Pittsfield's sewer system could support the increased flows from the facility.

Altresco plans to pretreat its wastewater discharge, including ph balancing, oil-water separation, and appropriate control technology for specific polluting chemicals (Exh. HO-1, p. 6-17 and Appendix A, pp. 4-23 to 4-25). Additionally, Altresco plans to take appropriate measures to ensure that runoff from any accidental spills of the contents of various storage tanks on the site would be properly directed and treated before release to Pittsfield's sewer system (Exh. HO-1, Appendix A, pp. 4-27 to 4-28; Tr. 2, pp. 32-33). The Company maintains that these measures would ensure that the quality of wastewater discharge meets Pittsfield's standards (Exh. HO-1, Appendix A, p. 4-23). Additionally, Mr. Barten stated that at no point would waste flows from the proposed facility pass through any portion of the Allendale Elementary School (Tr. 2, pp. 28-29)

Accordingly, the Siting Council finds that, with the mitigation measures proposed by Altresco, the proposed facilities would have an acceptable impact on the Pittsfield sewer system.

19/ Altresco identified the primary sources of the wastewater as demineralizer regeneration, boiler and cooling tower blowdown, filter backwash, and sanitary sewage (Exh. HO-1, p. 6-16).

5. Visual Impacts

The proposed site is a level, grassed area surrounded by a fringe of existing deciduous trees (Exh. HO-1, p. 6-19). The site's most recent use was as a high voltage direct current ("DC") test facility, and test facility structures of up to 100 feet in height are currently present on the site but would be removed to construct the proposed facilities (Exhs. HO-1, pp. 1-2, 6-19, HO-17).

Altresco stated that, in addition to the ancillary transmission and oil facilities, the generating facility would include two major buildings, 45 to 60 feet high; a mechanical cooling tower; various tanks and additional small buildings, all with heights in the range of 25 to 40 feet; and three 125-foot high exhaust stacks (Exh. HO-1, pp. 2-3 to 2-4). The stack height is based on the standards of good engineering practice as defined by the EPA (Exh. HO-EN-7). The proposed buildings are industrial in nature and their size is not large relative to other buildings within the GE-Pittsfield complex (Exh. HO-1, p. 6-20). Consequently, the proposed facilities would blend visually with the existing areas of heavy industrial facilities to the east and west of the site (id.).

Altresco stated that the use of simple structural elements, neutral colors, and new evergreen plantings, as well as existing vegetation, would minimize the visual impact of the proposed facilities on the surrounding areas (id.).[20]

The Siting Council finds that, with the inclusion of the new evergreen plantings, the construction of the proposed facilities would result in an acceptable visual impact on the surrounding community relative to the existing impact.

20/ Mr. Adams noted that the proposed site is slightly lower in elevation and has more existing vegetation than the alternate site rendering the alternate site slightly less preferable in relation to visual impacts (Tr. 2, pp. 55-57).

6. Safety

The primary safety concern raised during this proceeding relates to the use of ammonia (NH_3) necessary for operation of the SCR system.[21]

The Company stated that, while it knows of no instance of a rupture of a storage tank of the proposed design, a worst case tank rupture would result in NH_3 concentrations of no more than 500 ppm at the Altresco North, South, and West fence lines (Exh. A-11; Tr. 5, p. 102). Concentrations at the North, South, and West fence lines due to any pipe rupture similarly would be less than 500 ppm (id.). Mr. Adams stated that concentrations at the eastern fence line could be somewhat higher than 500 ppm, but that the area to the east is largely unoccupied and the closest use is for parking for the GE ordinance facilities (Tr. 5, p. 102). Concentrations outside the fence line would be even lower due to the greater dispersion area. Mr. Adams stated that the resulting concentrations at the Allendale Elementary School from a release at the proposed site would be less than 80 ppm (Tr. 5, p. 74).[22]

Altresco presented documentation related to the known health risks associated with exposure to various concentrations of NH_3 (Exh, A-11). These documents indicate that no lasting effect results from short exposures to NH_3 concentrations of up to 500 ppm (id.). However, at the time of hearing, the SCR ammonia storage and delivery system design had not been finalized, and DEQE had not approved the on-site storage of ammonia in any form (Tr. 5, pp. 60, 72).

21/ The Company originally planned to store large quantities of anhydrous ammonia in tanks on the site (Exh. HO-EN-8). Because of safety concerns related to the accidental release of ammonia, the DEQE ordered a study of the hazards associated with on site ammonia storage (id.). The Company addressed these concerns by changing the design of the ammonia storage and delivery system to allow for the use of a 25 - 30 percent solution of ammonium hydroxide (Exh. A-11; Tr. 5, pp. 60-61).

22/ A release at the alternate site would result in slightly higher concentrations at the school than a release at the proposed site (Tr. 5, p. 75).

In regard to possible accidents during transportation, the Company stated that the plant would require approximately five truck deliveries of ammonium hydroxide (NH_4OH) per month during full power operation (Tr. 5, pp. 64-65; Exh. A-11). Altresco provided that it would select delivery routes that avoid, as much as possible, occupied areas such as Allendale Elementary School (id.). Altresco noted that the deliveries would be made by qualified and licensed carriers (id.).

Altresco stated that emergency notification of the Allendale Elementary School and the surrounding community in the event of an ammonia release would proceed in accordance with an overall site emergency plan which is under development (Tr. 5, pp. 65-69; Exh. HO-EN-12). Possible forms of notification under consideration include automatic dialing and sirens (id.).

With regard to other hazardous materials that would likely be used at the site, such as gaseous chlorine, Altresco stated that any transportation, storage, and use would be in accordance with all applicable regulations and procedures (Exh. HO-EN-8).

In cases where a proposed site is in close proximity to residences or other sensitive aresa, the Siting Council must address health and safety concerns related to the transportation, storage, and use of hazardous materials. In this case, ammonia as well as other hazardous materials would be stored and used near the Allendale Elementary School, yet the Siting Council notes that the Allendale Elementary School and City officials have not been fully informed about the use of these materials. While the Company has stated that it would develop a plan to ensure the safety of the people at the Allendale Elementary School and nearby residents, it is critical that Altresco consult with Allendale Elementary School representatives and City officials in developing any emergency plans, in accordance with the ORDER set forth in Section IV, infra. Similarly, the Siting Council notes that Altresco has a continuing responsibility to advise and consult with appropriate Allendale Elementary School and Pittsfield city officials on any and all matters affecting the safety and health of residents.

Accordingly, based on the safety measures presented by the Company, the Siting Council finds that the proposed facilities would have acceptable safety impacts.

7. Conclusions on Environmental Impact

The Siting Council has found that, with the environmental mitigation proposed by Altresco, the environmental impacts of construction of the proposed facilities at the proposed site would have an acceptable impact on air quality, noise levels, water and sewer resources, visual impacts, and safety. Further, the Siting Council has found that, with the environmental mitigation proposed by Altresco, the proposed facility would, in fact, result in an overall improvement in air quality due to the retirement of the existing GE-Pittsfield steam plant. Accordingly, the Siting Council finds that construction and operation of the proposed facilities at the proposed site would have acceptable environmental impacts. However, in order to address certain safety impacts identified herein, the Siting Council ORDERS Altresco to comply with the first and second conditions set forth in Section IV, infra.

G. Conclusions on Proposed Facilities

The Siting Council has found that Altresco has considered a reasonable range of practical facility siting alternatives. In addition, the Siting Council has found that the costs of construction and operation of the proposed facilities at the proposed site are acceptable. Further, the Siting Council has found that the environmental impacts of construction and operation of the proposed facilities at the proposed site are acceptable. However, the Siting Council has made no finding on the reliability of the power generated at and transmitted from the proposed facility at the proposed site.

Accordingly, the Siting Council finds that the construction and operation of the proposed facilities at the proposed site is superior to alternatives in terms of costs and environmental impacts. However, in order to address certain environmental impacts identified herein, the Siting Council ORDERS Altresco to comply with the first and second conditions set forth in Section IV, infra.

IV. DECISION AND ORDER

The Siting Council finds that construction of the proposed facilities at the proposed site described herein is consistent with providing a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost.

Accordingly, the Siting Council hereby APPROVES the petition of Altresco, Inc. to construct a bulk generating facility subject to the following conditions:

(1) Altresco shall ensure that the final design of the ammonia transportation, storage, and delivery systems including, as necessary, location of the storage tank and pipe routes, limits NH_3 concentrations at the North, South, and West of the site perimeter and at the nearest occupied area to the east of the site perimeter to no more than 500 ppm in the event of a worst case rupture of any component of the system.

(2) Altresco shall ensure that any emergency plans for the site (1) are developed in consultation with City of Pittsfield officals and the Allendale Elementary School, and (2) include direct and immediate notification of the Allendale Elementary School in the event of any and all potentially significant hazardous material releases.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

Dated this 4th day of August, 1988

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 4, 1988, by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Barbara Anthony (for Paula W. Gold, Secretary of Consumer Affairs); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joseph W. Joyce (Public Labor Member); Stephen D. Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member).

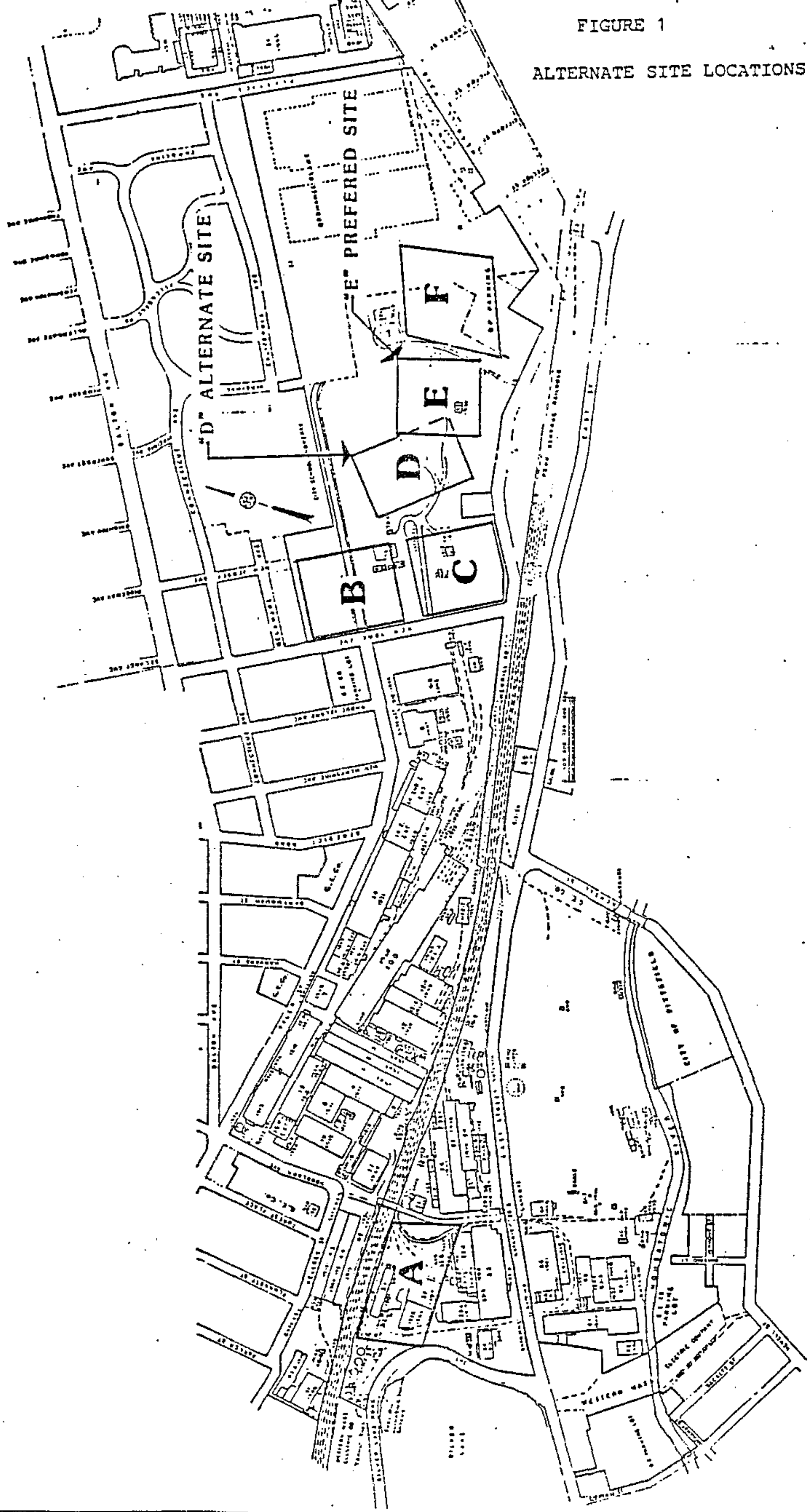
Sharon M. Pollard

Sharon M. Pollard, Chairperson

Dated this 4th day of August, 1988

FIGURE 1

ALTERNATE SITE LOCATIONS



SOURCE: Exh. HO-1, P. 5-8
FIGURE 5-1 ALTRESCO ALTERNATIVE SITES

TABLE 1

Altresco-Pittsfield, Inc.
Projections of NEPOOL Demand and Supply (Summer Peak)

Without Seabrook

Forecast Source	Year	NEPOOL Demand	NEPOOL Objective Capability	NEPOOL Supply	Supply Surplus/ (Deficit)	
NEPOOL	1988	20,127 MW	24,152 MW	24,082 MW	(70) MW	(0.3%)
1988	1990	21,293	25,552	26,053	501	2.0%
CELT	1995	23,935	28,722	24,632	(4,090)	(14.2%)
Report	2000	26,699	32,039	24,407	(7,632)	(23.8%)
Updated	1988	19,311	23,173	23,584	411	1.8%
OSP	1990	20,215	24,258	23,190	(1,068)	(4.4%)
	1995	21,921	26,305	24,325	(1,980)	(7.5%)
	2000	23,771	28,525	23,400	(5,125)	(18.0%)
Updated	1988	19,311	23,173	23,029	(144)	(0.6%)
NE Gov's	1990	20,886	25,063	23,425	(1,638)	(6.5%)
Confer	1995	24,075	28,890	24,561	(4,329)	(15.0%)
	2000	28,181	33,818	23,635	(10,183)	(30.1%)
Updated	1988	19,311	23,173	23,584	(411)	(1.8%)
Lee	1990	20,886	25,063	23,190	(1,873)	(7.5%)
	1995	24,163	28,996	24,325	(4,671)	(16.1%)
	2000	27,606	33,127	23,400	(9,727)	(29.4%)

Notes:

1. Altresco estimated NEPOOL's Objective Capability for the forecasts by NEPOOL, Ocean State Power, and Mr. Lee by assuming a constant reserve margin of 20 percent throughout the forecast periods.

2. The New England Governor's Conference projections are for all of New England rather than NEPOOL only. This difference is less than 0.5 percent.

3. All forecasts assume Pilgrim (668 MW) is on line.

Sources: Exhs. HO-3, HO-N-1b, HO-N-3a, HO-N-3b, HO-N-3c; Exh. A-2

TABLE 2

Altresco-Pittsfield, Inc.
Projections of NEPOOL Demand and Supply (Summer Peak)

With Seabrook

Forecast Source	Year	NEPOOL Demand	NEPOOL Objective Capability	NEPOOL Supply	Supply Surplus/ (Deficit)	
NEPOOL	1988	20,127 MW	24,152 MW	24,082 MW	(70) MW	(0.3%)
1988	1990	21,293	25,552	27,203	1,651	6.5%
CELT	1995	23,935	28,722	25,782	(2,940)	(10.2%)
Report	2000	26,699	32,039	25,557	(6,482)	(20.2%)
Updated	1988	19,311	23,173	24,734	1,561	6.7%
OSP	1990	20,215	24,258	24,340	82	0.3%
	1995	21,921	26,305	25,475	(830)	(3.2%)
	2000	23,771	28,525	24,550	(3,975)	(13.9%)
Updated	1988	19,311	23,173	24,179	1,006	4.3%
NEGC	1990	20,886	25,063	24,575	(488)	(1.9%)
	1995	24,075	28,890	25,711	(3,179)	(11.0%)
	2000	28,181	33,818	24,785	(9,033)	(26.7%)
Updated	1988	19,311	23,173	24,734	1,561	6.7%
Lee	1990	20,886	25,063	24,340	(723)	(2.9%)
	1995	24,163	28,996	25,475	(3,521)	(12.1%)
	2000	27,606	33,127	24,550	(8,577)	(25.9%)

Notes:

1. For the forecasts by NEPOOL, Ocean State Power, and Mr. Lee, Altresco estimated NEPOOL's Objective Capability by assuming a constant reserve margin of 20 percent throughout the forecast periods.

2. The New England Governor's Conference projections are for all of New England rather than NEPOOL only.

3. All forecasts assume 668 MW from Pilgrim.

4. All forecasts assume Seabrook in 1988 except NEPOOL which assumes Seabrook in 1989.

Sources: Exhs. HO-3, HO-N-1b, HO-N-3a, HO-N-3b, HO-N-3c; Exh. A-2

TABLE 3

Altresco-Pittsfield, Inc.
Estimated Annual Air Emissions
(Tons per Year)

Proposal vs. Alternative Approaches

Compound	Proposed Facility	Coal-Fired Alternative BACT	Coal-Fired Alternative LAER	Oil-Fired Alternative BACT	Oil-Fired Alternative LAER
Sulfer Dioxide	90	1600	800	1150	575
Nitrogen Oxides	213	3000	600	1600	320
Particulates	33	150	150	150	150
Carbon Monoxide	131	120	120	175	175
Non-Methane Hydrocarbons	16	14	14	27	27

Notes:

1. Best Available Control Technology (BACT) means the maximum reduction in pollutant emissions that is determined to be achievable, taking into account environmental, economic, and energy considerations.

2. Lowest Achievable Emission Rate (LAER) means the most stringent emission limitation which is achieved in practice or is required by any State Implementation Plan for a particular class or category of source.

3. The proposed project would use LAER.

Source: Exh. HO-8

Appeal as to matters of law from any final decision, order or ruling of the Siting Council may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Siting Council modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Siting Council within twenty days after the date of service of the decision, order or ruling of the Siting Council or within such further time as the Siting Council may allow upon request filed prior to the expiration of 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. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).